British Columbia Utilities Commission

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ORDER NUMBER
R-32-16A

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Mandatory Reliability Standards Assessment Report No. 9

BEFORE:
W. M. Everett, Commissioner

on July 18, 2016

ORDER

WHEREAS:

A. Pursuant to section 125.2(2) of the *Utilities Commission Act* (UCA) the British Columbia Utilities Commission (Commission) has exclusive jurisdiction to determine whether a "reliability standard" as defined in the UCA, is in the public interest and should be adopted in British Columbia (BC);

B. The Rules of Procedure for Reliability Standards in BC, adopted by Commission Order G-123-09, dated October 15, 2009, and amended by Commission Order R-33-15, states that a reliability standard does not include Compliance Provisions and defines Compliance Provisions as "the compliance-related provisions that accompany, but do not constitute part of, a Commission adopted Reliability Standard";

C. In order to facilitate the Commission's consideration of reliability standards, the British Columbia Hydro and Power Authority (BC Hydro) is required under section 125.2(3) of the UCA to review each reliability standard established by a standard-making body, such as the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), and provide the Commission with a report (MRS Assessment Report) assessing:

   (a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted;

   (b) the suitability of the reliability standard for BC;

   (c) the potential cost of the reliability standard if it were adopted;

      (c.1) the application of the reliability standard to persons or persons in respect of specified equipment if the reliability standard were adopted; and

   (d) any other matter prescribed by regulation or identified by order of the Commission;

D. Compliance Provisions, including effective dates, are not assessed by BC Hydro. This approach is consistent with that taken in previous Mandatory Reliability Standards (MRS) Assessment Reports;

E. Ministerial Order No. MO39 dated February 22, 2009, as amended, established a MRS regulation which specifies that BC Hydro must submit the MRS Assessment Report within a year of the date the reliability standard is adopted by the regulatory body with jurisdiction over the standard-making body that established the reliability standard;

F. In its October 19, 2015 letter to the Commission, BC Hydro requested an extension to allow certain reliability standards to be included in the MRS Assessment Report and to be assessed over a period of greater than a year pursuant to section 3(2) of the MRS Regulation. This extension request was approved by Commission Order R-45-15, dated October 29, 2015;

G. On April 28, 2016, BC Hydro filed MRS Assessment Report No. 9 (Report) assessing 17 new and revised/replacement standards (Revised Standards) developed by NERC and/or WECC. In the Report, BC Hydro used the date the reliability standard was adopted in the United States by the Federal Energy Regulatory Commission (FERC) as the date of regulatory approval to determine the reliability standards assessed during the Assessment Period (December 1, 2014 to November 30, 2015). BC Hydro assessed the reliability standards excluding the accompanying Compliance Provisions. If adopted, the 17 Revised Standards would supersede existing reliability standards previously adopted by the Commission;

H. The Revised Standards assessed by BC Hydro in the Report are based on defined terms contained in the NERC Glossary of Terms Used in Reliability Standards dated December 7, 2015 (NERC Glossary). The Report included an assessment of 13 new or revised defined glossary terms (Glossary Terms) and the retirement of of three Glossary Terms included in the NERC Glossary;

I. In the Report, BC Hydro concludes that 15 of the 17 Revised Standards and 10 of the 13 Glossary Terms are suitable for adoption in BC at this time. BC Hydro also concludes that the three retired Glossary Terms “Critical Assets”, “Critical Cyber Assets”, and “Reliability Directive” should be retired in BC;

J. To date, BC Hydro has acted as the Planning Authority/Planning Coordinator (PA/PC) for the BC Hydro asset footprint only. The PA/PC responsibilities for the province require clarification at this time. Revised Standards PRC-006-2 and PRC-010-2 considered in the Report contain requirements that pertain to the PC function and BC Hydro recommends these reliability standards be held in abeyance and be of no force or effect in BC until the PC function is resolved. BC Hydro does not recommend Glossary Terms “Remedial Action Scheme” and “Under Voltage Load Shedding Program”, intended for PRC-010-2, for adoption in BC at this time;

K. BC Hydro recommends that, in connection with the recommendation for adoption of PRC-002-2 and CIP-014-2, BC-specific versions of the FERC approved PRC-002-2 and CIP-014-2 Implementation Plans be implemented in BC. BC Hydro provided BC-specific versions of the PRC-002-2 and CIP-014-2 Implementation Plans as part of the Report for the Commission’s consideration;

L. By Commission Order R–15-16 dated May 5, 2016, BC Hydro was directed to publish a Notice of Mandatory Reliability Standards Assessment Report No. 9 and Process for Public Comments and established the Regulatory Timetable for a public comment process;

M. In its letter dated May 25, 2016, Catalyst Paper Corporation (Catalyst Paper) submitted suggestions to delay implementation of COM-001-2.1 R4 until meaningful technical consultation with affected entities has been made and also suggested that future assessment reports include a local technical workshop to minimize participant costs and to ensure entities have an opportunity to quickly clarify any uncertainty regarding proposed changes (Exhibit C1-1);

N. On May 26, 2016, FortisBC Inc. submitted that its feedback is reflected in the Report and that it has no further comments (Exhibit C2-1);

O. On June 9, 2016, BC Hydro provided its reply comments (Exhibit B-2) stating it had considered the feedback from all entities to establish the recommended adoption date for COM-001-2.1 R4, including Catalyst Paper's request to delay the implementation of COM-001-2.1 R4. As a result, and to allow for an implementation period for COM-001-2.1 R4, BC Hydro included in the Report the recommended BC effective date to be 12 months after the standard is adopted by the Commission. Further, in its reply comments, BC Hydro indicated its support for the use of local workshops and informed Catalyst Paper of the many opportunities for such provided by NERC and WECC. BC Hydro had no response to the submission by FortisBC Inc.;

P. Pursuant to section 125.2(6) of the UCA, the Commission must adopt the Reliability Standard(s) addressed in the Report if the Commission considers that the Reliability Standard(s) are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the Reliablity Standard(s);

Q. The Commission has reviewed and considered the Report, the Revised Standards and Glossary Terms assessed therein, as well as the comments received and considers that the adoption of the recommendations in the Report is warranted; and

R. Although not assessed by BC Hydro, the Commission considers that the Compliance Provisions of the Reliability Standards should be adopted to maintain compliance monitoring consistency with other jurisdictions that have adopted the Reliability Standards with the Compliance Provisions and finds it appropriate to provide effective dates for entities to come into compliance with the Revised Standards and Glossary Terms adopted in this order.

NOW THEREFORE pursuant to subsections 125.2(6) and 125.2(10) of the *Utilities Commission Act,* the British Columbia Utilities Commission (Commission) orders as follows:

1. The Commission adopts the 15 Revised Standards recommended for adoption in the British Columbia Hydro and Power Authority Mandatory Reliability Standards Assessment Report No. 9 with effective dates in Table 1 of Attachment A to this order and each standard to be superseded by a standard adopted in this order shall remain in effect until the effective date of the standard superseding it.

2. As a result of this order and previous Commission orders, all the Reliability Standards listed in Attachment B to this order are in effect in British Columbia (BC) as of the dates shown. The effective dates for the Reliability Standards listed in Attachment B supersede the effective dates that were included in any similar list appended to any previous order. Attachment B to this order also includes those Reliability Standards with effective dates held in abeyance to be assessed at a later date.

3. Individual requirements within Reliability Standards that incorporate, by reference, Reliability Standards that have not been adopted by the Commission, are of no force and effect in BC.

4. Individual requirements or sub-requirements within Reliability Standards, which the Commission has adopted but for which the Commission has not determined an effective date, are of no force and effect in BC.

5. The Commission adopts the North American Electric Reliability Corporation (NERC) Glossary of Terms Used in Reliability Standards, dated December 7, 2015, to define terms employed in the Reliability Standards (Glossary Terms). The effective date of each of the new or revised Glossary Terms adopted in this order is

the date in Table 2 of Attachment A to this order. Each Glossary Term to be superseded by a revised Glossary Term adopted in this order shall remain in effect until the effective date of the Glossary Term superseding it. The Commission retires three Glossary Terms as attached in Table 2 of Attachment A to this order.

6. As a result of this order and previous Commission orders, the Glossary Terms listed in Attachment C to this order are Glossary Terms in effect in BC as of the effective dates indicated. The effective dates for the Glossary Terms listed in Attachment C supersede the effective dates that were included in any similar list appended to any previous order.

7. The Commission directs that Glossary Terms within the NERC Glossary of Terms used in Reliability Standards dated December 7, 2015, that do not include a United States Federal Energy Regulatory Commission approval date on or before November 30, 2015, are of no force or effect in BC.

8. The Commission directs that the Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary of Terms used in Reliability Standards, dated December 7, 2015, are of no force or effect in BC.

9. The Commission adopts the Compliance Provisions as defined in the Rules of Procedure for Reliability Standards in British Columbia, that accompany each of the adopted Reliability Standards, in the form directed by the Commission and as amended from time to time.

10. The Commission directs that the BC-specific versions of the PRC-002-2 and CIP-014-2 Implementation Plans, in the form directed by the Commission and as amended from time to time, be adopted and made effective in BC as in Attachment D to this order. The BC-specific versions of the PRC-002-2 and CIP-014-2 Implementation Plans will be posted on the Western Electricity Coordinating Council website with links from the Commission website.

11. The Reliability Standards adopted in BC by the Commission will be posted on the Western Electricity Coordinating Council website with a link from the Commission website.

12. The Commission confirms that entities subject to Mandatory Reliability Standards are required to report to the Commission and may, on a voluntary basis, report to NERC as an Electric Reliability Organization or to the Federal Energy Regulatory Commission.

13. The Reliability Standards are adopted as set out in Attachment E to this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 9th day of November 2016.

BY ORDER

Original Signed By:

W. M. Everett
Commissioner

Attachments

British Columbia Utilities Commission
Reliability Standards and Glossary Terms Adopted by this Order

Table 1: Reliability Standards with Effective Dates as Adopted by this Order

Standard	Standard Name	Effective Date	Type	Commission Approved Standard(s) Being Superseded[1]
BAL-003-1.1	Frequency Response and Frequency Bias Setting	The first day of the first calendar quarter after BCUC adoption	Revised	BAL-003-1
CIP-014-2	Physical Security	**Requirement(R)1**: The first day of the first calendar quarter that is twelve months after BCUC adoption. **R2**: The initial performance of R2 Parts 2.1, 2.2, and 2.4 shall be completed within three months of the effective date of R1. The initial performance of R2, Part 2.3 shall be completed within two months of the completion of performance under R2 Part 2.2. **R3**: The initial performance of R3 shall be completed within one week of completion of performance under R2. **R4**: The initial performance of R4 shall be completed within three months of completion of performance under R2. **R5**: The initial performance of R5 shall be completed within six months of completion of performance under R2.	New	n/a

[1] Commission approved Reliability Standard(s) to be superseded by the revised Reliability Standard assessed.

Standard	Standard Name	Effective Date	Type	Commission Approved Standard(s) Being Superseded[1]
		R6: Initial performance of R6, Parts 6.1, 6.2, and 6.4 shall be completed within three months of completion of performance under R5. Initial performance of R6, Part 6.3 shall be completed within two months of R6 Part 6.2. In connection with the recommendation to adopt the reliability standard, BC Hydro recommends that a BC-specific version of the CIP-014-2 Implementation Plan be implemented in BC pursuant to an order of the Commission providing for the administration of adopted reliability standards.		
COM-001-2.1	Communications	The first day of the first calendar quarter that is 12 months after BCUC adoption	Revised	COM-001-1.1
COM-002-4	Operating Personnel Communications Protocols	The first day of the first calendar quarter that is six months after BCUC adoption	Revised	COM-001-1.1 Requirement 4 and COM-002-2
MOD-031-1	Demand and Energy Data	The first day of the first calendar quarter after BCUC adoption	New	MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1
PRC-001-1.1(ii)	System Protection Coordination	The first day of the first calendar quarter after BCUC adoption	Revised	PRC-001-1.1

Standard	Standard Name	Effective Date	Type	Commission Approved Standard(s) Being Superseded[1]
PRC-002-2	Disturbance Monitoring and Reporting Requirements	**R1, R5**: The first day of the first calendar quarter six months after BCUC adoption. **R2-R4, R6-R11**: At least 50% compliant within four years after BCUC adoption and fully compliant within six years after BCUC adoption. **R12**: The first day of the first calendar quarter nine months after BCUC adoption. In connection with the recommendation to adopt the reliability standard, BC Hydro recommends that a BC-specific version of the PRC-002-2 Implementation Plan be implemented in BC pursuant to an order of the Commission providing for the administration of adopted reliability standards.	New	PRC-018-1
PRC-004-5(i)	Protection System Misoperation Identification and Correction	The first day of the first calendar quarter that is 12 months after BCUC adoption.	Revised	PRC-004-2.1a
PRC-005-2(i)	Protection System Maintenance	Follow the same staged BC-specific PRC-005-2 Implementation Plan adopted under BCUC Order R-38-15. Effective dates remain the same as those for PRC-005-2 adopted under BCUC Order R-38-15.	Revised	PRC-005-2
PRC-006-2	Automatic Under Frequency Load Shedding	Adoption held in abeyance at this time[2].	New	n/a

[2] Unable to assess based on undefined Planning Coordinator/Planning Authority footprints and entities responsible. The BCUC Reasons for Decision for Order R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to BC.

Standard	**Standard Name**	**Effective Date**	**Type**	**Commission Approved Standard(s) Being Superseded**[1]
PRC-010-2	Under Voltage Load Shedding	Adoption held in abeyance at this time[2].	Revised	PRC-010-0
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	Align with effective dates of PRC-019-1 in BC per BCUC Order R-38-15 after BCUC adoption: 40% compliant on October 1, 2017 60% compliant on October 1, 2018 80% compliant on October 1, 2019 100% compliant on October 1, 2020.	Revised	PRC-019-1
PRC-024-2	Generator Frequency and Voltage Protective Relay Settings	Align with the staged effective dates of PRC-024-1 in BC per BCUC Order R-38-15 after BCUC adoption: 40% compliant by October 1, 2017 60% compliant by October 1, 2018 80% compliant by October 1, 2019 100% compliant by October 1, 2020.	Revised	PRC-024-1
VAR-001-4.1	Voltage and Reactive Control	The later of either October 1, 2016, or the first day of the first calendar quarter after BCUC adoption.	Revised	VAR-001-4
VAR-002-4	Generator Operation for Maintaining Network Voltage Schedules	The later of either the effective date of VAR-002-3 in BC (October 1, 2016), or immediately after adoption by the BCUC.	Revised	VAR-002-3
VAR-002-WECC-2	Automatic Voltage Regulators	The later of either October 1, 2016 or the first day of the first calendar quarter, after BCUC adoption.	Revised	VAR-002-WECC-1
VAR-501-WECC-2	Power System Stabilizer	The later of either October 1, 2016 or the first day of the first calendar quarter, after BCUC adoption.	Revised	VAR-501-WECC-1

Table 2: NERC Glossary Terms with Effective Dates as Adopted by this Order

NERC Glossary Term[1]	Acronym	Effective Date	Commission Approved Term to be Replaced or Retired[2]
Alternative Interpersonal Communication	-	Align with effective date of COM-001-2.1 standard where this term is referenced.	-
Composite Protection System	-	Align with effective date of PRC-004-5(i) standard where this term is referenced.	-
Critical Assets	-	Retire as of September 30, 2018; one day prior to the effective date of the CIP Version 5 standards in BC (October 1, 2018).	Critical Assets
Critical Cyber Assets	-	Retire as of September 30, 2018; one day prior to the effective date of the CIP Version 5 standards in BC (October 1, 2018).	Critical Cyber Assets
Demand-Side Management	DSM	Align with effective date of MOD-031-1 standard where this term is referenced.	Demand-Side Management
Energy Emergency	-	The first day of the first calendar quarter after BCUC adoption.	Energy Emergency
Interpersonal Communication	-	Align with effective date of COM-001-2.1 standard where this term is referenced.	-

[1] FERC approved terms in the NERC Glossary of Terms as of December 7, 2015.

[2] Commission approved terms in the NERC Glossary of Terms as of October 1, 2014 as adopted by the Commission Order R-38-15.

NERC Glossary Term[1]	**Acronym**	**Effective Date**	**Commission Approved Term to be Replaced or Retired[2]**
Misoperation	-	Align with effective date of PRC-004-5(i) standard where this term is referenced.	Misoperation
Operating Instruction	-	Align with effective date of COM-002-4 standard where this term is referenced.	-
Operational Planning Analysis	-	The first day of the first calendar quarter after BCUC adoption.	Operational Planning Analysis
Protection System Maintenance Program (PRC-005-4)	PSMP	Not recommended for adoption in BC at this time.[3]	Protection System Maintenance Program (PRC-005-2)
Real-time Assessment	-	The first day of the first calendar quarter after BCUC adoption.	Real-time Assessment
Reliability Directive	-	Retire the first day of the first calendar quarter after BCUC adoption of the Report.	Reliability Directive
Remedial Action Scheme	RAS	Adoption held in abeyance at this time; to be re-assessed with PRC-010-2.[4]	Remedial Action Scheme
Total Internal Demand	-	Align with effective date of MOD-031-1 standard where this term is referenced.	-
Under Voltage Load Shedding Program	UVLS Program	Adoption held in abeyance at this time; to be re-assessed with PRC-010-2.[4]	-

[3] Intended for reliability standard PRC-005-4 which was deferred by FERC and is not included in this Report.

[4] The NERC Glossary Term is associated with reliability standard PRC-010-2 that is dependent on the Planning Authority/Planning Coordinator function. The BCUC Reasons for Decision for Order R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to BC.

British Columbia Utilities Commission
Reliability Standards with Effective Dates adopted in British Columbia

Standard	Name	Commission Order Adopting	Effective Date
BAL-001-1[1]	Real Power Balancing Control Performance	R-32-14	October 1, 2014
BAL-001-2	Real Power Balancing Control Performance	R-14-16	July 1, 2016
BAL-002-1	Disturbance Control Performance	R-41-13	December 12, 2013
BAL-002-WECC-2	Contingency Reserve	R-32-14	October 1, 2014
BAL-003-1[1]	Frequency Response and Frequency Bias Setting	R-38-15	R1: April 1, 2016 R2-R4: October 1, 2015
BAL-003-1.1	Frequency Response and Frequency Bias Setting	R-32-16	October 1, 2016
BAL-004-0	Time Error Correction	G-67-09	November 1, 2010
BAL-004-WECC-2	Automatic Time Error Correction	R-32-14	October 1, 2014
BAL-005-0.2b	Automatic Generation Control	R-41-13	December 12, 2013 R2: Retired January 21, 2014[2]
BAL-006-2	Inadvertent Interchange	R-1-13	April 15, 2013
CIP-002-3[1]	Cyber Security – Critical Cyber Asset Identification	G-162-11	July 1, 2012
CIP-002-5.1	Cyber Security – BES Cyber System Categorization	R-38-15	October 1, 2018
CIP-003-3[1, 3, 4]	Cyber Security – Security Management Controls	G-162-11	July 1, 2012 R1.2, R3, R3.1, R3.2, R3.3, and R4.2:Retired January 21, 2014[2]
CIP-003-5	Cyber Security – Security Management Controls	R-38-15	October 1, 2018
CIP-004-3a[1]	Cyber Security - Personnel & Training	R-32-14	August 1, 2014
CIP-004-5.1	Cyber Security – Personnel & Training	R-38-15	October 1, 2018

[1] Reliability Standard is superseded by the revised/replacement reliability standard listed immediately below it as of the effective date(s) of the revised/replacement reliability standard.
[2] On November 21, 2013, FERC Order 788 (referred to as Paragraph 81) approved the retiring of the Reliability Standard requirements.
[3] Reliability Standard is superseded by CIP-010-1 as of the CIP-010-1 effective date.
[4] Reliability standard is superseded by CIP-011-1 as of the CIP-011-1 effective date.

Standard	Name	Commission Order Adopting	Effective Date
CIP-005-3a[1, 3]	Cyber Security – Electronic Security Perimeter(s)	R-1-13	July 15, 2013 R2.6: Retired January 21, 2014[2]
CIP-005-5	Cyber Security – Electronic Security Perimeter(s)	R-38-15	October 1, 2018
CIP-006-3c[1]	Cyber Security – Physical Security of Critical Cyber Assets	G-162-11	July 1, 2012
CIP-006-5	Cyber Security – Physical Security of BES Cyber Systems	R-38-15	October 1, 2018
CIP-007-3a[1, 3, 4]	Cyber Security – Systems Security Management	R-32-14	August 1, 2014 R7.3: Retired January 21, 2014[2]
CIP-007-5	Cyber Security – System Security Management	R-38-15	October 1, 2018
CIP-008-3[1]	Cyber Security – Incident Reporting and Response Planning	G-162-11	July 1, 2012
CIP-008-5	Cyber Security – Incident Reporting and Response Planning	R-38-15	October 1, 2018
CIP-009-3[1]	Cyber Security – Recovery Plans for Critical Cyber Assets	G-162-11	July 1, 2012
CIP-009-5	Cyber Security – Recovery Plans for BES Cyber Systems	R-38-15	October 1, 2018
CIP-010-1	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-38-15	October 1, 2018
CIP-011-1	Cyber Security – Information Protection	R-38-15	October 1, 2018
CIP-014-2	Physical Security	R-32-16	October 1, 2017 and as per BC-specific Implementation Plan
COM-001-1.1[1, 5]	Telecommunications	G-167-10	January 1, 2011
COM-001-2.1	Communications	R-32-16	October 1, 2017
COM-002-2[1]	Communication and Coordination	G-67-09	November 1, 2010
COM-002-4	Operating Personnel Communications Protocols	R-32-16	April 1, 2017
EOP-001-2.1b	Emergency Operations Planning	R-32-14	August 1, 2014
EOP-002-3.1	Capacity and Energy Emergencies	R-32-14	August 1, 2014

[5] Requirement 4 of the Reliability Standard is superseded by COM-002-4 as of the COM-002-4 effective date.

Standard	Name	Commission Order Adopting	Effective Date
EOP-003-1[6]	Load Shedding Plans	G-67-09	November 1, 2010
EOP-003-2	Load Shedding Plans		Adoption held in abeyance at this time[7]
EOP-004-2	Event Reporting	R-32-14	August 1, 2015
EOP-005-2	System Restoration and Blackstart Resources	R-32-14	August 1, 2015 R3.1: Retired January 21, 2014[2]
EOP-006-2	System Restoration Coordination	R-32-14	August 1, 2014
EOP-008-1	Loss of Control Center Functionality	R-32-14	August 1, 2015
EOP-010-1	Geomagnetic Disturbance Operations	R-38-15	R1, R3: October 1, 2016 R2: Upon retirement of IRO-005-3.1a
FAC-001-1[1]	Facility Connection Requirements	R-32-14	November 1, 2014
FAC-001-2	Facility Interconnection Requirements	R-38-15	October 1, 2016
FAC-002-2	Facility Interconnection Studies	R-38-15	October 1, 2015
FAC-003-3	Transmission Vegetation Management	R-32-14	August 1, 2015
FAC-501-WECC-1	Transmission Maintenance	R-1-13	April 15, 2013
FAC-008-3	Facility Ratings	R-32-14	August 1, 2015 R4, R5: Retired January 21, 2014[2]
FAC-010-2.1	System Operating Limits Methodology for the Planning Horizon	G-162-11	October 30, 2011 R5: Retired January 21, 2014[2]
FAC-011-2	System Operating Limits Methodology for the Operations Horizon	G-167-10	January 1, 2011 R5: Retired January 21, 2014[2]
FAC-013-1[8]	Establish and Communicate Transfer Capability	G-67-09	November 1, 2010
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon		Adoption held in abeyance at this time[7]

[6] Reliability Standard would be superseded by EOP-003-2 if adopted in BC. Adoption of EOP-003-2 pending reassessment.
[7] Unable to assess based on undefined Planning Coordinator/Planning Authority footprints and entities responsible. The Commission Reasons for Decision for Order R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to BC.
[8] Reliability Standard would be superseded by the FAC-013-2 if adopted in BC. Adoption of FAC-013-2 pending reassessment.

Standard	Name	Commission Order Adopting	Effective Date
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
INT-004-3.1	Dynamic Transfers	R-38-15	R1, R2: October 1, 2015 R3: January 1, 2016
INT-006-4	Evaluation of Interchange Transactions	R-38-15	October 1, 2015
INT-009-2.1	Implementation of Interchange	R-38-15	October 1, 2015
INT-010-2.1	Interchange Initiation and Modification for Reliability	R-38-15	October 1, 2015
INT-011-1.1	Intra-Balancing Authority Transaction Identification	R-38-15	October 1, 2015
IRO-001-1.1	Reliability Coordination Responsibilities and Authorities	G-167-10	January 1, 2011
IRO-002-2	Reliability Coordination – Facilities	R-1-13	April 15, 2013
IRO-003-2	Reliability Coordination – Wide Area View	G-67-09	November 1, 2010
IRO-004-2	Reliability Coordination – Operations planning	R-1-13	April 15, 2013
IRO-005-3.1a[9]	Reliability Coordination – Current Day Operations	R-32-14	August 1, 2014
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-2	Qualified Transfer Path Unscheduled Flow (USF) Relief	R-38-15	October 1, 2015
IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments	R-1-13	April 15, 2013
IRO-009-1	Reliability Coordinator Actions to Operate Within IROLs	R-1-13	April 15, 2013
IRO-010-1a	Reliability Coordinator Data Specification and Collection	R-1-13	April 15, 2013
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability coordinators	G-67-09	November 1, 2010
IRO-015-1	Notification and Information Exchange	G-67-09	November 1, 2010

[9] Requirement 3 of the Reliability Standard is superseded by EOP-010-1 Requirement 2 as of the EOP-010-1 Requirement 2 effective date.

Standard	Name	Commission Order Adopting	Effective Date
IRO-016-1	Coordination of Real-Time Activities	G-67-09	November 1, 2010 R2: Retired January 21, 2014[2]
MOD-001-1a	Available Transmission System Capability	G-175-11	November 30, 2011
MOD-004-1	Capacity Benefit Margin	G-175-11	November 30, 2011
MOD-008-1	Transmission Reliability Margin Calculation Methodology	G-175-11	November 30, 2011
MOD-010-0[10]	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0[10]	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-016-1.1[11]	Documentation of Data Reporting Requirements for Actual and Forecast Demand, New Energy for Load, and Controllable Demand-Side Management	G-167-10	January 1, 2011
MOD-017-0.1[11]	Aggregated Actual and Forecast Demands and Net Energy for Load	G-167-10	January 1, 2011
MOD-018-0[11]	Treatment of Non-member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	G-67-09	November 1, 2010
MOD-019-0.1[11]	Reporting of Interruptible Demands and Direct Control Load Management	G-167-10	January 1, 2011
MOD-020-0	Providing Interruptible Demands and Direct Control Load management Data to System Operators and Reliability Coordinators	G-67-09	November 1, 2010

[10] Reliability Standard will be superseded by MOD-032-1 and MOD-033-1 if adopted in BC. Adoption of MOD-032-1 and MOD-033-1 pending reassessment.
[11] Reliability Standard is superseded by MOD-031-1 as of the MOD-031-1 effective date.

Standard	Name	Commission Order Adopting	Effective Date
MOD-021-1[11]	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts	R-1-13	April 15, 2013
MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
MOD-026-1	Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October. 1, 2025 R3-R6: October 1, 2015
MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R5: October 1, 2015
MOD-028-2	Area Interchange Methodology	R-32-14	August 1, 2014
MOD-029-1a	Rated System Path Methodology	G-175-11	November 30, 2011
MOD-030-2	Flowgate Methodology	G-175-11	November 30, 2011
MOD-031-1	Demand and Energy Data	R-32-16	October 1, 2016
MOD-032-1	Data for Power System Modeling and Analysis	R-38-15	Effective date held in abeyance[7]
MOD-033-1	Steady-State and Dynamic System Model Validation	R-38-15	Effective date held in abeyance[7]
NUC-001-3	Nuclear Plant Interface Coordination	R-38-15	January 1, 2016
PER-001-0.2	Operating Personnel Responsibility and Authority	R-41-13	December 12, 2013
PER-002-0	Operating Personnel Training	G-67-09	November 1, 2010
PER-003-1	Operating Personnel Credentials	R-41-13	January 1, 2015
PER-004-2	Reliability Coordination – Staffing	R-1-13	January 15, 2013
PER-005-1[1]	System Personnel Training	R-1-13	R1, R2: January 15, 2015 R3: July 15, 2014 R3.1: January 15, 2016
PER-005-2	Operations Personnel Training	R-38-15	R1-R4, R6: October 1, 2016 R5: October 1, 2017

Standard	Name	Commission Order Adopting	Effective Date
PRC-001-1.1[1]	System Protection Coordination	R-38-15	October 1, 2015
PRC-001-1.1(ii)	System Protection Coordination	R-32-16	October 1, 2016
PRC-002-2	Disturbance Monitoring and Reporting Requirements	R-32-16	R1, R5: April 1, 2017 R2-R4, R6-R11: staged as per BC-specific Implementation Plan R12: July 1, 2017
PRC-004-2.1a[1]	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	R-32-14	August 1, 2014
PRC-004-5(i)	Protection System Misoperation Identification and Correction	R-32-16	October 1, 2017
PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation	R-1-13	July 15, 2013
PRC-005-1.1b[1]	Transmission and Generation Protection System Maintenance and Testing	R-32-14	January 1, 2015
PRC-005-2[1]	Protection System Maintenance	R-38-15	R1, R2, R5: October 1, 2017 R3, R4: staged as per BC-specific Implementation Plan
PRC-005-2(i)	Protection System Maintenance	R-32-16	R1, R2, R5: October 1, 2017 R3, R4: staged as per BC-specific Implementation Plan
PRC-006-1[1]	Automatic Underfrequency Load Shedding		Adoption held in abeyance at this time[7]
PRC-006-2	Automatic Underfrequency Load Shedding		Adoption held in abeyance at this time[7]
PRC-007-0[12]	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0[13]	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010

[12] Reliability Standard will be superseded by PRC-006-2 if adopted in BC. Adoption of PRC-006-2 pending reassessment.
[13] Reliability Standard is superseded by PRC-005-2 as of the PRC-005-2 effective date.

Standard	Name	Commission Order Adopting	Effective Date
PRC-009-0[12]	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	November 1, 2010
PRC-010-0[1]	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	November 1, 2010 R2: Retired January 21, 2014[2]
PRC-010-2	Undervoltage Load Shedding		Adoption held in abeyance at this time[7]
PRC-011-0[13]	Undervoltage Load Shedding System Maintenance and Testing	G-67-09	November 1, 2010
PRC-015-0	Special Protection System Data and Documentation	G-67-09	November 1, 2010
PRC-016-0.1	Special Protection System Misoperations	G-167-10	January 1, 2011
PRC-017-0[13]	Special Protection System Maintenance and Testing	G-67-09	November 1, 2010
PRC-018-1[14]	Disturbance Monitoring Equipment Installation and Data Reporting	G-67-09	November 1, 2010
PRC-019-1[1]	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	R-32-16	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-021-1[15]	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010

[14] Reliability Standard is superseded by PRC-002-2 as of the PRC-002-2 effective date.
[15] Reliability Standard is superseded by PRC-010-2 as of the PRC-010-2 effective date.

Standard	Name	Commission Order Adopting	Effective Date
PRC-022-1[15]	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010 R2: Retired January 21, 2014[2]
PRC-023-2[1, 16]	Transmission Relay Loadability	R-41-13	R1-R5: For circuits identified by sections 4.2.1.1 and 4.2.1.4: January 1, 2016 For circuits identified by sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6: To be determined[7] R6: To be determined[7]
PRC-023-3	Transmission Relay Loadability	R-38-15	R1-R5: regarding circuits 4.2.1.1 and 4.2.1.4: January 1, 2016 R1-R5: Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5 and 4.2.1.6: To be determined[7] R6: To be determined[7]
PRC-024-1[1]	Generator Frequency and Voltage Protective Relay Settings	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-024-2	Generator Frequency and Voltage Protective Relay Settings	R-32-16	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-025-1	Generator Relay Loadability	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
TOP-001-1a	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-002-2.1b	Normal Operations Planning	R-41-13	December 12, 2013
TOP-003-1	Planned Outage Coordination	R-1-13	April 15, 2013
TOP-004-2	Transmission Operations	G-167-10	January 1, 2011

[16] PRC-023-2 Requirement 1, Criterion 6 only is superseded by PRC-025-1 as of PRC-025-1's 100 percent effective date.

Standard	Name	Commission Order Adopting	Effective Date
TOP-005-2a	Operational Reliability Information	R-1-13	April 15, 2013
TOP-006-2	Monitoring System Conditions	R-1-13	April 15, 2013
TOP-007-0	Reporting System Operating Unit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	November 1, 2010
TOP-007-WECC-1a	System Operating Limits	R-38-15	October 1, 2015
TOP-008-1	Response to Transmission Limit Violations	G-67-09	November 1, 2010
TPL-001-0.1[17]	System Performance Under Normal (No Contingency) Conditions (Category A)	G-167-10	January 1, 2011
TPL-001-4	Transmission System Planning Performance Requirements	Adoption pending reassessment	To be determined
TPL-002-0b[17]	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	R-1-13	January 15, 2013
TPL-003-0b[17]	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	R-32-14	August 1, 2014
TPL-004-0a[17]	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	R-32-14	August 1, 2014
VAR-001-3[1]	Voltage and Reactive Control	R-32-14	R1, R2, R6-R12: August 1, 2014 E.A. 13-E.A.18: August 1, 2015 R5: Retired January 21, 2014[2]
VAR-001-4[1]	Voltage and Reactive Control	R-38-15	October 1, 2016
VAR-001-4.1	Voltage and Reactive Control	R-32-16	October 1, 2016
VAR-002-2b[1]	Generator Operation for Maintaining Network Voltage Schedules	R-32-14	August 1, 2014

[17] Reliability Standard will be superseded by TPL-001-4 if adopted in BC. Adoption of TPL-001-4 pending reassessment.

Standard	Name	Commission Order Adopting	Effective Date
VAR-002-3[1]	Generator Operation for Maintaining Network Voltage Schedules	R-38-15	October 1, 2016
VAR-002-4	Generator Operation for Maintaining Network Voltage Schedules	R-32-16	October 1, 2016
VAR-002-WECC-1[1]	Automatic Voltage Regulators (AVR)	R-1-13	January 15, 2014
VAR-002-WECC-2	Automatic Voltage Regulators (AVR)	R-32-16	October 1, 2016
VAR-501-WECC-1[1]	Power System Stabilizer (PSS)	R-11-13	January 15, 2014
VAR-501-WECC-2	Power System Stabilizer (PSS)	R-32-16	October 1, 2016

British Columbia (BC) Exceptions to the Glossary of Terms Used in North American Electric Reliability Corporation (NERC) Reliability Standards (NERC Glossary)

Updated: July 18, 2016

Introduction:

This document is to be used in conjunction with the NERC Glossary dated December 7, 2015.

- The NERC Glossary terms listed in Table 1 below are effective in BC on the date specified in the "Effective Date" column.
- Table 2 below outlines the adoption history by the Commission of the NERC Glossaries in BC.
- Any NERC Glossary terms and definitions in the NERC Glossary that are not approved by FERC on or before November 30, 2015 are of no force or effect in BC.
- Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in BC, with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in BC.
- The Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary have been adopted by the NERC Board of Trustees for use in regional standards and are of no force or effect in BC.

Table 1: BC Effective Date Exceptions to Definitions in December 7, 2015 Version of the NERC Glossary

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Adjacent Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Alternative Interpersonal Communication	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Area Control Error (from NERC section of the Glossary)	ACE	Report No. 7	R-32-14	Adoption	October 1, 2014
Area Control Error (from the WECC Regional Definitions section of the Glossary)	ACE	Report No. 7	R-32-14	Retirement	October 1, 2014
Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Attaining Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Automatic Time Error Correction	-	Report No. 7	R-32-14	Adoption	October 1, 2014
BES Cyber Asset	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
BES Cyber System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
BES Cyber System Information	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Blackstart Capability Plan	-	Report No. 7	R-32-14	Retirement	August 1, 2015
Blackstart Resource	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Bulk Electric System	BES	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System	-	Report No. 8	R-38-15	-	October 1, 2015
Bus-tie Breaker	-	Report No. 8	R-38-15	Adoption	To be determined[1]
CIP Exceptional Circumstance	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
CIP Senior Manager	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Composite Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Composite Protection System	-	Report No. 9	R-32-16	Adoption	October 1, 2017

[1] NERC Glossary term is specific to the TPL-001-04 reliability standard. NERC Glossary term will be assessed in a TPL-001-4 specific assessment report.

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Consequential Load Loss	-	Report No. 8	R-38-15	Adoption	To be determined[1]
Control Center	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Critical Assets	-	Report No. 9	R-32-16	Retirement	September 30, 2018
Critical Cyber Assets	-	Report No. 9	R-32-16	Retirement	September 30, 2018
Cyber Assets	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Demand-Side Management	DSM	Report No. 9	R-32-16	Adoption	October 1, 2016
Dial-up Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Dynamic Interchange Schedule or Dynamic Schedule	-	Report No. 8	R-38-15	Adoption	October 1, 2015

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Electronic Access Control or Monitoring Systems	EACMS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Electronic Access Point	EAP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Electronic Security Perimeter	ESP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Energy Emergency	-	Report No. 9	R-32-16	Adoption	October 1, 2016
External Routable Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Frequency Bias Setting	-	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Measure	FRM	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Obligation	FRO	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Frequency Response Sharing Group	FRSG	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Interactive Remote Access	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interconnection Reliability Operating Limit	IROL	Report No. 6	R-41-13	Adoption	December 12, 2013
Intermediate Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Intermediate System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interpersonal Communication	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Long-Term Transmission Planning Horizon	-	Report No. 8	R-38-15	Adoption	To be determined[1]
Minimum Vegetation Clearance Distance	MVCD	Report No. 7	R-32-14	Adoption	August 1, 2015
Misoperation	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Native Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Non-Consequential Load Loss	-	Report No. 8	R-38-15	Adoption	To be determined[1]
Operating Instruction	-	Report No. 9	R-32-16	Adoption	April 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Operational Planning Analysis[2]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Operational Planning Analysis[2]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Operational Planning Analysis	-	Report No. 9	R-32-16	Adoption	October 1, 2016
Operations Support Personnel	-	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 5 of the PER-005-2 standard where this term is referenced
Physical Access Control Systems	PACS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Physical Security Perimeter	PSP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Planning Assessment	-	Report No. 8	R-38-15	Adoption	To be determined[1]
Protected Cyber Assets	PCA	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.

[2] NERC Glossary term definition is superseded by the revised NERC Glossary term definition listed immediately below it as of the effective date(s) of the revised NERC Glossary term definition.

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Protection System	-	Report No. 6	R-41-13	Adoption	January 1, 2015 for each entity to modify its protection system maintenance and testing program to reflect the new definition (to coincide with recommended effective date of PRC-005-1b) and until the end of the first complete maintenance and testing cycle to implement any additional maintenance and testing for battery chargers as required by that entity's program.
Protection System Maintenance Program	PSMP	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 1 of the PRC-005-2 standard where this term is referenced
Protection System Maintenance Program *(PRC-005-4)*[3]	PSMP	Report No. 9		-	Not recommended for adoption in BC at this time.
Pseudo-Tie	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Real-time Assessment[2]	-	Report No. 6	R-41-13	Adoption	January 1 , 2014
Real-time Assessment	-	Report No. 9	R-32-16	Adoption	October 1, 2016
Reliability Adjustment Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Reliability Directive	-	Report No. 9	R-32-16	Retirement	July 18, 2016
Reliability Standard	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliable Operation	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Relief Requirement (WECC Regional Term)	-	Report No. 8	R-38-15	Adoption	Align with effective date of IRO-006-WECC-2 standard where this term is referenced

[3] Intended for reliability standard PRC-005-4 which was deferred by FERC and is not included in MRS Assessment Report No. 9.

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Remedial Action Scheme	RAS	Report No. 9		-	To be determined[4]
Reportable Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Request for Interchange	RFI	Report No. 8	R-38-15	Adoption	October 1, 2015
Sink Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Source Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
System Operator	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) as reference is made to the term Control Center as part of the definition of System Operator. The term Control Center is in turn referenced from the CIP Version 5 standards.
Total Internal Demand	-	Report No. 9	R-32-16	Adoption	October 1, 2016
Under Voltage Load Shedding Program	-	Report No. 9		-	To be determined[4]
Right-of-Way	ROW	Report No. 7	R-32-14	Adoption	August 1, 2015
TLR (Transmission Loading Relief) Log	-	Report No. 7	R-32-14	Adoption	August 1, 2014
Vegetation Inspection	-	Report No. 7	R-32-14	Adoption	August 1, 2015

[4] The NERC Glossary term is associated with reliability standard PRC-010-2 that is dependent on the Planning Authority/Planning Coordinator function. The BCUC Reasons for Decision for Order R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to BC.

Table 2: NERC Glossary Adoption History in BC

NERC Glossary of Terms Version Date	Assessment Report Number	Commission Order Adoption Date	Commission Order Adopting	Effective Date
February 12, 2008	Report No. 1	June 4, 2009	G-67-09	The NERC Glossary is effective as of the date of the Order (June 4, 2009)
April 20, 2010	Report No. 2	November 10, 2010	G-167-10	The NERC Glossary is effective as of the date of the Order (November 10, 2010)
August 4, 2011	Report No. 3	September 1, 2011	G-162-11 Replacing G-151-11	The NERC Glossary is effective as of the date of the Order (September 1, 2011)
December 13, 2011	Report No. 5	January 15, 2013	R-1-13	The NERC Glossary is effective as of the date of the Order (January 15, 2013) NERC Glossary terms which have not been approved by FERC are of no force or effect
December 5, 2012	Report No. 6	December 12, 2013	R-41-13	The NERC Glossary is effective as of the date of the Order (December 12, 2013) The effective date of the new and revised NERC Glossary terms adopted in the Order is the date appearing in the table found in Attachment A to the Order NERC Glossary terms which have not been approved by FERC are of no force or effect

NERC Glossary of Terms Version Date	Assessment Report Number	Commission Order Adoption Date	Commission Order Adopting	Effective Date
January 2, 2014	Report No. 7	July 17, 2014	R-32-14	The NERC Glossary is effective as of the date of the Order (July 17, 2014) The effective date of the new and revised NERC Glossary terms adopted in the Order is the date appearing in the table found in Attachment A to the Order. Each Glossary term to be superseded by a revised Glossary term adopted in the Order shall remain in effect until the effective date of the Glossary term superseding it. The NERC Glossary terms listed in the tables found in Attachment C to the Order are all of the NERC Glossary terms in effect in B.C. as of the effective dates listed in the tables of Attachment C to the Order. The effective dates for the NERC Glossary terms that are listed in the tables found in Attachment C supersede the effective dates that were included in any similar list appended to any previous order. NERC Glossary terms which have not been approved by FERC are of no force or effect. The Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary of Terms are of no force or effect in BC.
October 1, 2014	Report No. 8	July 24, 2015	R-38-15	The NERC Glossary is effective as of the date of Commission Order R-38-15.
December 7, 2015	BAL-001-2	April 21, 2016	R-14-16	The BAL-001-2 Glossary Terms (Interconnection, Regulation Reserve Sharing Group, Reporting Ace and Reserve Sharing Group Reporting Ace) became effective as of July 1, 2016[1]

[1] With the adoption of the NERC Glossary as part of MRS Assessment Report No. 9, the BAL-001-2 Glossary Terms are no longer exceptions to the NERC Glossary and so are not included in Table 1.

NERC Glossary of Terms Version Date	Assessment Report Number	Commission Order Adoption Date	Commission Order Adopting	Effective Date
December 7, 2015	Report No. 9	July 18, 2016	R-32-16	The NERC Glossary is effective as of July 18, 2016. The effective date of the new and revised NERC Glossary terms adopted in the Order is the date appearing in the table found in Attachment A to the Order.

BCUC CIP-014-2 Implementation Plan

Approvals Requested
CIP-014-2 Physical Security

Prerequisite Approvals
None

Effective Date: July 18, 2016

New or Revised Standards
CIP-014-2 is effective as of October 1, 2017.

Standards for Retirement
None

Initial Performance of Periodic Requirements
The initial risk assessment required by CIP-014-2, Requirement R1, must be completed on or before the effective date of the standard. Subsequent risk assessments shall be performed according to the timelines specified in CIP-014-2, Requirement R1.

The initial performance of CIP-014-2, Requirements R2 through R6, must be completed according to the timelines specified after the effective date of the proposed Reliability Standard, as follows:

Requirement R2 shall be completed as follows:

- Parts 2.1, 2.2, and 2.4 shall be completed within three months of the effective date of the proposed Reliability Standard.
- Part 2.3 shall be completed within two months of the completion of performance under Requirement R2 part 2.2.

Requirement R3 shall be completed within one week of completion of performance under Requirement R2.

Requirement R4 shall be completed within three months of completion of performance under Requirement 2.

Requirement R5 shall be completed within six months of completion of performance under Requirement R2.

Requirement R6 shall be completed as follows:

- Parts 6.1, 6.2, and 6.4 shall be completed within three months of completion of performance under Requirement R5.
- Part 6.3 shall be completed within two months of Requirement R6 part 6.2.

BCUC PRC-002-2 Implementation Plan

Approvals Requested
PRC-002-2 Disturbance Monitoring and Reporting Requirements

Requested Retirements
PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting

Prerequisite Approvals
None

Applicable Entities
- Planning Coordinator
- Reliability Coordinator
- Transmission Owner
- Generator Owner

Revisions to Defined Terms in the NERC Glossary
None

Background
The Implementation Plan reflects consideration of the following:

1. This standard reflects the need for data, rather than equipment, with the understanding that the data is collected from Disturbance Monitoring Equipment distributed across the BES.
2. A significant amount of sequence of events recording (SER), fault recording (FR), and dynamic Disturbance recording (DDR) capability already exists on the BES. The monitoring requirements in this standard align with industry practices. Therefore, many existing recordings can satisfy the Requirements and Implementation Plan put forth.
3. Fault MVA data is readily available or calculable by the Transmission Owners for the BES buses they own. Therefore, six (6) months is adequate time for generating the list of BES buses following the methodology described in Attachment 1 (for Requirement R1).
4. Responsible entities have the relevant data and information pertaining to the BES Elements requiring DDR and six (6) months is adequate time for working with any affected entities and generating the list of BES Elements.
5. The nine (9) month time period for R12 includes the six (6) month implementation for R1 and R5, and a three (3) month additional time period to make notifications. The nine (9) months for R12 implementation is reasonable for the contents of that requirement.
6. A total percentage of BES buses and BES Elements established in Requirements R1 and R5 respectively are used in the Implementation Plan since these lists are explicitly created and readily available. It is expected that many monitoring requirements will become compliant without significant changes to recording capability.
7. A graduated approach to implementation recognizes that progress will be made while attempting to minimize any potential significant impact to the entities.

8. Implementation of Disturbance monitoring recording following changes to the system are addressed by following re-evaluation of the lists as per Requirement R1 and Requirement R5.
9. Implementing SER, FR, and DDR capability may require scheduled outages for both Transmission Owners and Generator Owners. Generator Owners may have outage cycles of 24 months or more depending on the type and characteristics of the generating units or plant. Meanwhile, Transmission Owners probably will have more BES Elements requiring SER, FR, and DDR and may have to schedule outages across the system. The Implementation Plan takes scheduling outages into account.
10. An entity owning only one (1) identified BES bus, BES Element, or generating unit is allowed six (6) years for implementation to accommodate normal outage schedules.
11. The Implementation Plan accounts for any increase in requests to vendors for this technology or capability that could impact implementation timelines for the respective entities.

General Considerations

Each Transmission Owner and Generator Owner subject to PRC-018-1 shall maintain the ability to provide Disturbance monitoring data using current methods required by PRC-018-1 until the entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. As required in PRC-018-1 Disturbance Monitoring Equipment Installation and Data Reporting, Requirement R1, Parts 1.1 and 1.2, it is expected that the Transmission Owner and Generator Owner will have those functionalities with regard to their current Disturbance data.

Effective Date

The standard shall become effective April 1, 2017

Standard(s) for Retirement

Each Transmission Owner and Generator Owner shall maintain documentation to demonstrate compliance with PRC-018-1 until that entity meets the requirements of PRC-002-2 in accordance with this Implementation Plan. Standard PRC-018-1 shall remain effective throughout the phased implementation period of PRC-002-2 and shall be applicable to an entity's Disturbance monitoring and reporting activities not yet transitioned to PRC-002-2. PRC-018-1 will be retired following full implementation of PRC-002-2 as noted below.

PRC-018-1 Midnight of the day immediately prior to six (6) years after the effective date of PRC-002-2 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for PRC-002-2 Requirements R1 and R5

Entities shall be 100 percent compliant on the first day of the first calendar quarter six (6) months after the date that the standard is approved by the BCUC.

Implementation Plan for PRC-002-2 Requirement R12

Entities shall be 100 percent compliant on the first day of the first calendar quarter nine (9) months after the date that the standard is approved by the BCUC.

Implementation Plan for PRC-002-2 Requirements R2, R3, R4, R6, R7, R8, R9, R10 and R11:

Entities shall be at least 50 percent compliant within four (4) years of the effective date of PRC-002-2 and fully compliant within six (6) years of the effective date.

Entities that own only one (1) identified BES bus, BES Element, or generating unit shall be fully compliant within six (6) years of the effective date.

Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity (as defined within the PRC-002-2 standard; Western Interconnection – Reliability Coordinator) that re-evaluated the list.

Conforming Changes to Other Standards

Where conflicts between the continent-wide standard PRC-002-2 and a regional standard exist, entities should comply with PRC-002-2. Conflicts will be addressed in the appropriate regional standards development process.

- PRC-002-2 Requirement R3 stipulates data must be captured by FR to determine electrical quantities.
- PRC-002-2 Requirement R5 stipulates the capture of DDR data for HVDC.
- PRC-002-2 Requirement R8 recognizes DDR that is not continuous, and includes triggering data for DDR that is not continuous.

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-1.1**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Balancing Authority

   4.1.1. The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.2. Frequency Response Sharing Group

5. **Effective Date*:**

   5.1. In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.

   5.2. In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.

B. Requirements

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. *[Risk Factor: High][Time Horizon: Real-time Operations]*

R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or

- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

C. Measures

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.3 Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.4 Additional Compliance Information

For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation

	calendar days from the implementation period specified by the ERO.	days from the implementation period specified by the ERO.	days from the implementation period specified by the ERO.	period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the

				Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

E. Regional Variance

None

F. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29,	BOT approved errata changes	Errata

	2008		
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Attachment A

BAL-003-1 Frequency Response & Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- CB_R which is the statistically determined ratio of the Point C to Value B
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Starting Frequency (F_{Start})	**59.974**	**59.976**	**59.963**	**59.972**	Hz
Prevailing UFLS First Step	**59.5***	**59.5**	**59.3**	**58.5**	Hz
Base Delta Frequency (DF_{Base})	**0.474**	**0.476**	**0.663**	**1.472**	Hz
CC_{ADJ}	**0.007**	**0.004**	**0.012**	**N/A**	Hz
Delta Frequency (DF_{CC})	**0.467**	**0.472**	**0.651**	**1.472**	Hz
CB_R	**1.000**	**1.625**	**1.377**	**1.550**	
Delta Frequency (DF_{CBR})	**0.467**	**0.291**	**0.473**	**0.949**	Hz
BC'_{ADJ}	**0.018**	**N/A**	**N/A**	**N/A**	Hz
Max. Delta Frequency (MDF)	**0.449**	**0.291**	**0.473**	**0.949**	
Resource Contingency Criteria (RCC)	**4,500**	**2,740**	**2,750**	**1,700**	MW
Credit for Load Resources (CLR)		**300**	**1,400****		MW
IFRO	**-1,002**	**-840**	**-286**	**-179**	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual “Output of Generating Plants” within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual $Load_{BA}$ is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO’s.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that contains the sum of each participant’s individual event performance.

Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.

If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.

If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.

Frequency Response Measure (FRM)

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its

Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event NA_I, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

Target Date	Activity
April 30	The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).
May 10	Form1 is posted with selected events from the first quarter for BA usage by the ERO.
May 15	The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.
July 15	The BAs provide load and generation data as described in Attachment A to the ERO.
July 30	The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).
August 10	Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.
October 30	The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)
November 10	Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.
November 20	If necessary, the ERO provides any updates to the necessary Frequency Response.
November 20	The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.
January 30	The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).
2nd business day in February	Form1 is posted with all selected events for the year for BA usage by the ERO.
February 10	The ERO assigns FRO values to the BAs for the upcoming year.
March 7	BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.
March 24	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.
Any time during first 3 business days of April (unless specified otherwise by the ERO)	The BA implements any changes to their FBS and L10 value.

A. Introduction

1. **Title:** Physical Security

2. **Number:** CIP-014-2

3. **Purpose:** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a "protected area," as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates*:

See BC-specific Implementation Plan for CIP-014-2.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, *Reliability Standards for Physical Security Measures*, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. *[VRF: High; Time-Horizon: Long-term Planning]*

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. *[VRF: Medium; Time-Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner's risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. *[VRF: Lower; Time-Horizon: Long-term Planning]*

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.

R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: *[VRF: High; Time-Horizon: Long-term Planning]*

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. *[VRF: Medium; Time-Horizon: Long-term Planning]*

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.

- An entity or organization approved by the ERO.

- A governmental agency with physical security expertise.

- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or

- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner's and Transmission Operator's facilities.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could	The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability,	The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a	uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk	Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.	subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.	assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.	Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months; OR The Transmission

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
R2	**Long-term Planning**	**Medium**	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but less than or equal to 100 calendar days following completion	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but less than or equal to 110 calendar days following completion	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to 120 calendar days following completion of Requirement R1;	The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days following completion of Requirement R1;

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.	of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.	OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to modify or document the technical basis for not	OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					modifying its identification under R1 as required by Part 2.3.	
R3	**Long-term Planning**	**Lower**	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 11	The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center identified in Requirement R1; OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.	Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.	calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.	The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1.
R4	**Operations Planning,**	**Medium**	N/A	The Responsible Entity conducted an	The Responsible Entity conducted an	The Responsible Entity failed to

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Long-term Planning			evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider one of Parts 4.1 through 4.3 in the evaluation.	evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to consider two of Parts 4.1 through 4.3 in the evaluation.	conduct an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1; OR The Responsible Entity conducted an evaluation of the potential physical threats and vulnerabilities to each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but failed to

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						consider Parts 4.1 through 4.3.
R5	**Long-term Planning**	**High**	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 130 calendar days but less than or equal to 140 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 140 calendar days but less than or equal to 150 calendar days after completing Requirement R2; OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its	The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 150 calendar days after completing the verification in Requirement R2; OR The Responsible Entity failed to develop and implement a documented physical security

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.	Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.	Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.	plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Parts 5.1 through 5.4 in the plan.
R6	**Long-term Planning**	**Medium**	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the	The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in	The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days; OR The Responsible Entity failed to have an affiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5; OR The Responsible

R #	Time Horizon	VRF	Violation Severity Levels (CIP-014-1)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.	reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.	Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.	Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 1, 2015	Effective Date	New
2	April 16, 2015	Revised to meet FERC Order 802 directive to remove “widespread”.	Revision
2	May 7, 2015	Adopted by the NERC Board of Trustees	
2	July 14, 2015	FERC Letter Order in Docket No. RD15-4-000 approving CIP-014-2	

Guidelines and Technical Basis

Section 4 Applicability

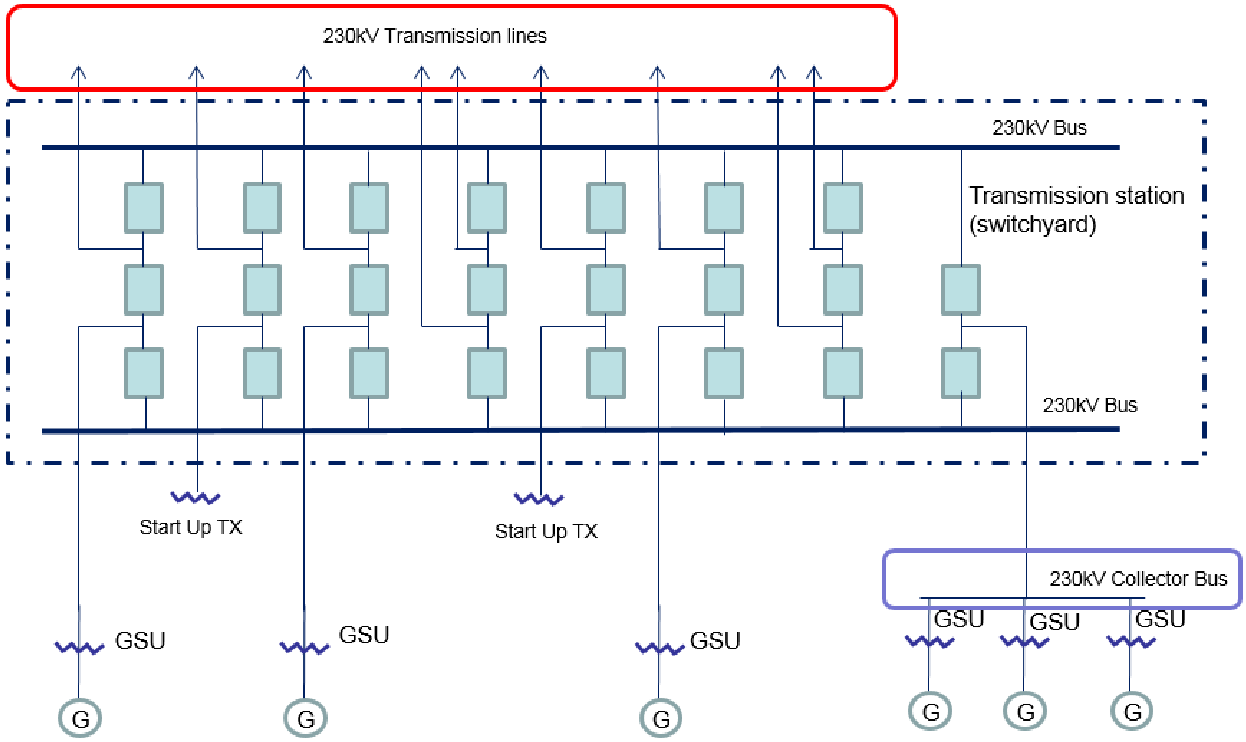
The purpose of Reliability Standard CIP-014 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator's obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause instability, uncontrolled separation, or Cascading within an

Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.



Also, the SDT uses the phrase “Transmission stations or Transmission substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014 standard.

Requirement R1

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the

Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. The requirement is not to require identification of, and thus, not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

<u>Performing Risk Assessments</u>

The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;

(b) Voltage deviation exceeding ± 10%; or

(c) Cascading outage/voltage collapse; or

(d) Frequency below under-frequency load shed points

Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center "operationally controls" a Transmission station or Transmission substation when the control center's electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause instability, uncontrolled separation, or Cascading within an Interconnection.
3. Review of the Requirement R1 risk assessment methodology.

This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (*i.e.,* the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the "verification may occur concurrent with or after the risk assessment performed under Requirement R1." This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (*i.e.,* concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity's understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
- The entity's familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner's site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only "need to know" employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

Requirement R3

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or as a result of the verification process under Requirement R2.

Requirement R4

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- NERC Security Guideline for the Electricity Sector: Physical Security.
- NERC Security Guideline: Physical Security Response.
- ASIS International General Risk Assessment Guidelines.
- ASIS International Facilities Physical Security Measure Guideline.

- ASIS International Security Management Standard: Physical Asset Protection.
- Whole Building Design Guide - Threat/Vulnerability Assessments.

Requirement R5

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:

- *Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.*

  Resiliency may include, among other things:

  a. System topology changes,

  b. Spare equipment,

  c. Construction of a new Transmission station or Transmission substation.

  While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

- *Law enforcement contact and coordination information.*

  Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

- *A timeline for executing the physical security enhancements and modifications specified in the physical security plan.*

  Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

- *Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).*

  A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5.

Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

Requirement R6

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (*i.e.,* the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

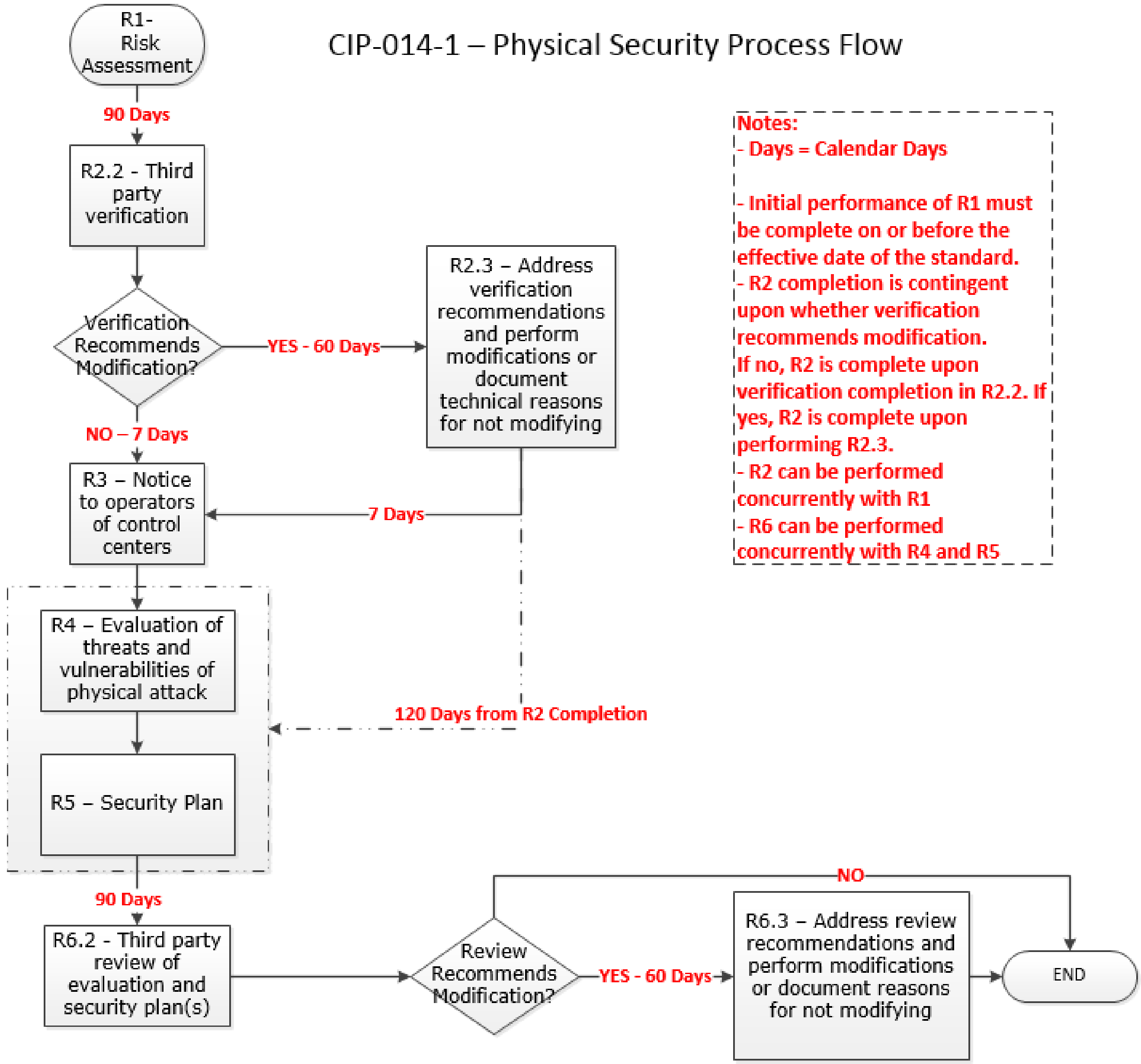
- *An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.*

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- *An entity or organization approved by the ERO.*
- *A governmental agency with physical security expertise.*
- *An entity or organization with demonstrated law enforcement, government, or military physical security expertise.*

As with the verification under Requirement R2, Requirement R6 provides that the "review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5." This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (*i.e.,* concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.

Timeline


CIP-014-1 – Physical Security Process Flow
R1- Risk Assessment
90 Days
R2.2 - Third party verification
Verification Recommends Modification?
YES - 60 Days
R2.3 – Address verification recommendations and perform modifications or document technical reasons for not modifying
NO – 7 Days
R3 – Notice to operators of control centers
7 Days
R4 – Evaluation of threats and vulnerabilities of physical attack
120 Days from R2 Completion
R5 – Security Plan
90 Days
R6.2 - Third party review of evaluation and security plan(s)
Review Recommends Modification?
YES - 60 Days
NO
R6.3 – Address review recommendations and perform modifications or document reasons for not modifying
END
Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:
This requirement meets the FERC directive from paragraph 6 of its March 7, 2014 order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through instability, uncontrolled separation, or cascading failures. The requirement is not intended to bring within the scope of the standard a Transmission station or Transmission substation unless the applicable Transmission Owner determines through technical studies and analyses based on objective analysis, technical expertise, operating experience and experienced judgment that the loss of such facility would have a critical impact on the operation of the Interconnection in the event the asset is rendered inoperable or damaged. In the November 20, 2014 Order, FERC reiterated that "only an instability that has a "critical impact on the operation of the interconnection" warrants finding that the facility causing the instability is critical under Requirement R1." The Transmission Owner may determine the criteria for critical impact by considering, among other criteria, any of the following:

- Criteria or methodology used by Transmission Planners or Planning Coordinators in TPL-001-4, Requirement R6
- NERC EOP-004-2 reporting criteria
- Area or magnitude of potential impact

Requirement R1 also meets the FERC directive for periodic reevaluation of the risk assessment by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (*i.e.,* the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

Rationale for Requirement R2:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term "unaffiliated" means that the selected verifying entity cannot be a corporate affiliate (*i.e.*, the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term "unaffiliated" is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.

Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility's location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.

Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity's security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Rationale for Requirement R6:
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.

A. Introduction

1. **Title:** **Communications**

2. **Number:** COM-001-2.1

3. **Purpose:** To establish Interpersonal Communication capabilities necessary to maintain reliability.

4. **Applicability:**

   4.1. Transmission Operator

   4.2. Balancing Authority

   4.3. Reliability Coordinator

   4.4. Distribution Provider

   4.5. Generator Operator

5. **Effective Date*:** The first day of the second calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

1.2. Each adjacent Reliability Coordinator within the same Interconnection.

R2. Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

2.1. All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

2.2. Each adjacent Reliability Coordinator within the same Interconnection.

R3. Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

3.1. Its Reliability Coordinator.

3.2. Each Balancing Authority within its Transmission Operator Area.

3.3. Each Distribution Provider within its Transmission Operator Area.

3.4. Each Generator Operator within its Transmission Operator Area.

3.5. Each adjacent Transmission Operator synchronously connected.

3.6. Each adjacent Transmission Operator asynchronously connected.

R4. Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

4.1. Its Reliability Coordinator.

4.2. Each Balancing Authority within its Transmission Operator Area.

4.3. Each adjacent Transmission Operator synchronously connected.

4.4. Each adjacent Transmission Operator asynchronously connected.

R5. Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

5.1. Its Reliability Coordinator.

5.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.

5.3. Each Distribution Provider within its Balancing Authority Area.

5.4. Each Generator Operator that operates Facilities within its Balancing Authority Area.

5.5. Each Adjacent Balancing Authority.

R6. Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

6.1. Its Reliability Coordinator.

6.2. Each Transmission Operator that operates Facilities within its Balancing Authority Area.

6.3. Each Adjacent Balancing Authority Area.

R7. Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

7.1. Its Balancing Authority.

7.2. Its Transmission Operator.

R8. Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

8.1. Its Balancing Authority.

8.2. Its Transmission Operator.

R9. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. *[Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]*

R10. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R11. Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request evidence that it has Interpersonal Communication capability with all Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and with each adjacent Reliability Coordinator within the same Interconnection, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R1.)

M2. Each Reliability Coordinator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with all Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and with each adjacent Reliability Coordinator within the same Interconnection, which could include, but is not limited to:

- physical assets, or

- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R2.)

M3. Each Transmission Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority, Distribution Provider, and Generator Operator within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously or synchronously connected, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communication. (R3.)

M4. Each Transmission Operator shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Balancing Authority within its Transmission Operator Area, and each adjacent Transmission Operator asynchronously and synchronously connected, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R4.)

M5. Each Balancing Authority shall have and provide upon request evidence that it has Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator and Generator Operator that operates Facilities within its Balancing Authority Area, each Distribution Provider within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R5.)

M6. Each Balancing Authority shall have and provide upon request evidence that it designated an Alternative Interpersonal Communication capability with its Reliability Coordinator, each Transmission Operator that operates Facilities within its Balancing Authority Area, and each adjacent Balancing Authority, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R6.)

M7. Each Distribution Provider shall have and provide upon request evidence that it has Interpersonal Communication capability with its Transmission Operator and its Balancing Authority, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R7.)

M8. Each Generator Operator shall have and provide upon request evidence that it has Interpersonal Communication capability with its Balancing Authority and its Transmission Operator, which could include, but is not limited to:

- physical assets, or
- dated evidence, such as, equipment specifications and installation documentation, test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R8.)

M9. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it tested, at least once each calendar month, its Alternative Interpersonal Communication capability designated in Requirements R2, R4, or R6. If the test was unsuccessful, the entity shall have and provide upon request evidence that it initiated action to repair or designated a replacement Alternative Interpersonal Communication capability within 2 hours. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R9.)

M10. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have and provide upon request evidence that it notified entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasted 30 minutes or longer. Evidence could include, but is not limited to: dated and time-stamped test records, operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R10.)

M11. Each Distribution Provider and Generator Operator that detected a failure of its Interpersonal Communication capability shall have and provide upon request evidence that it consulted with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine mutually agreeable action to restore the Interpersonal Communication capability. Evidence could include, but is not limited to: dated operator logs, voice recordings, transcripts of voice recordings, or electronic communications. (R11.)

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D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The Reliability Coordinator, Transmission Operator, Balancing Authority, Distribution Provider, and Generator Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Reliability Coordinator for Requirements R1, R2, R9, and R10, Measures M1, M2, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Transmission Operator for Requirements R3, R4, R9, and R10, Measures M3, M4, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Balancing Authority forRequirements R5, R6, R9, and R10, Measures M5, M6, M9, and M10 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Distribution Provider for Requirements R7 and R11, Measures M7 and M11 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.
- The Generator Operator for Requirements R8 and R11, Measures M8 and M11 shall retain written documentation for the most recent twelve calendar months and voice recordings for the most recent 90 calendar days.

If a Reliability Coordinator, Transmission Operator, Balancing Authority, Distribution Provider, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	The Reliability Coordinator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R1, Parts 1.1 or 1.2, except when the Reliability Coordinator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Reliability Coordinator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R1, Parts 1.1 or 1.2, except when the Reliability Coordinator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R2	N/A	N/A	The Reliability Coordinator failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R2, Parts 2.1 or 2.2.	The Reliability Coordinator failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R2, Parts 2.1 or 2.2.
R3	N/A	N/A	The Transmission Operator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R3, Parts 3.1, 3.2, 3.3, 3.4, 3.5, or 3.6, except when the Transmission Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Transmission Operator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R3, Parts 3.1, 3.2, 3.3, 3.4, 3.5, or 3.6, except when the Transmission Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R4	N/A	N/A	The Transmission Operator failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R4, Parts 4.1, 4.2, 4.3, or 4.4.	The Transmission Operator failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R4, Parts 4.1, 4.2, 4.3, or 4.4.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	The Balancing Authority failed to have Interpersonal Communication capability with one of the entities listed in Requirement R5, Parts 5.1, 5.2, 5.3, 5.4, or 5.5, except when the Balancing Authority detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.	The Balancing Authority failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R5, Parts 5.1, 5.2, 5.3, 5.4, or 5.5, except when the Balancing Authority detected a failure of its Interpersonal Communication capability in accordance with Requirement R10.
R6	N/A	N/A	The Balancing Authority failed to designate Alternative Interpersonal Communication capability with one of the entities listed in Requirement R6, Parts 6.1, 6.2, or 6.3.	The Balancing Authority failed to designate Alternative Interpersonal Communication capability with two or more of the entities listed in Requirement R6, Parts 6.1, 6.2, or 6.3.
R7	N/A	N/A	The Distribution Provider failed to have Interpersonal Communication capability with one of the entities listed in Requirement R7, Parts 7.1 or 7.2, except when the Distribution Provider detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.	The Distribution Provider failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R7, Parts 7.1 or 7.2, except when the Distribution Provider detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	N/A	N/A	The Generator Operator failed to have Interpersonal Communication capability with one of the entities listed in Requirement R8, Parts 8.1 or 8.2, except when a Generator Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.	The Generator Operator failed to have Interpersonal Communication capability with two or more of the entities listed in Requirement R8, Parts 8.1 or 8.2, except when a Generator Operator detected a failure of its Interpersonal Communication capability in accordance with Requirement R11.
R9	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 2 hours and less than or equal to 4 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 4 hours and less than or equal to 6 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 6 hours and less than or equal to 8 hours upon an unsuccessful test.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to test the Alternative Interpersonal Communication capability once each calendar month. OR The Reliability Coordinator, Transmission Operator, or Balancing Authority tested the Alternative Interpersonal Communication capability but failed to initiate action to repair or designate a replacement Alternative Interpersonal Communication in more than 8 hours upon an unsuccessful test.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R10	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 60 minutes but less than or equal to 70 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 70 minutes but less than or equal to 80 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 80 minutes but less than or equal to 90 minutes.	The Reliability Coordinator, Transmission Operator, or Balancing Authority failed to notify the entities identified in Requirements R1, R3, and R5, respectively upon the detection of a failure of its Interpersonal Communication capability in more than 90 minutes.
R11	N/A	N/A	N/A	The Distribution Provider or Generator Operator that detected a failure of its Interpersonal Communication capability failed to consult with each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of the Interpersonal Communication capability.

E. Regional Differences

None identified.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	April 4, 2007	Regulatory Approval — Effective Date	New
1	April 6, 2007	Requirement 1, added the word “for” between “facilities” and “the exchange.”	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to “1.1”	Errata
2	November 7, 2012	Adopted by Board of Trustees	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Replaced R1 with R1-R8; R2 replaced by R9; R3 included within new R1; R4 remains enforce pending Project 2007-02; R5 redundant with EOP-008-0, retiring R5 as redundant with EOP-008-0, R1; retiring R6, relates to ERO procedures; R10 & R11, new.
2	April 16, 2015	FERC Order issued approving COM-001-2	
2.1	August 25, 2015	Changed numbered parts under Requirement R6 to line up with the appropriate requirement.	Errata
2.1	November 13, 2015	FERC Letter Order approved errata to COM-001-2.1. Docket RD15-6-000	Errata

A. Introduction

1. **Title:** Operating Personnel Communications Protocols
2. **Number:** COM-002-4
3. **Purpose:** To improve communications for the issuance of Operating Instructions with predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the Bulk Electric System (BES).
4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Balancing Authority

   4.1.2 Distribution Provider

   4.1.3 Reliability Coordinator

   4.1.4 Transmission Operator

   4.1.5 Generator Operator

5. **Effective Date*:** The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements

R1. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*

1.1. Require its operating personnel that issue and receive an oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations.

1.2. Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions:

- Confirm the receiver's response if the repeated information is correct.
- Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver.

- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.

1.3. Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions:

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct.
- Request that the issuer reissue the Operating Instruction.

1.4. Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.

1.5. Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification.

1.6. Specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction.

R2. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*

R3. Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: *[Violation Risk Factor: Low][Time Horizon: Long-term Planning]*

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
- Request that the issuer reissue the Operating Instruction.

R4. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: *[Violation Risk Factor: Medium][Time Horizon: Operations Planning]*

4.1. Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols.

4.2. Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.

R5. Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*

- Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6).
- Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or
- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.

R6. Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
- Request that the issuer reissue the Operating Instruction.

R7. Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. *[Violation Risk Factor: High][Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its documented communications protocols developed for Requirement R1.

M2. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its initial training records related to its documented communications protocols developed for Requirement R1 such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R2.

M3. Each Distribution Provider and Generator Operator shall provide its initial training records for its operating personnel such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R3.

M4. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide evidence of its assessments, including spreadsheets, logs or other evidence of feedback, findings of effectiveness and any changes made to its documented communications protocols developed for Requirement R1 in fulfillment of

Requirement R4. The entity shall provide, as part of its assessment, evidence of any corrective actions taken where an operating personnel's non-adherence to the protocols developed in Requirement R1 is the sole or partial cause of an Emergency and for all other instances where the entity determined that it was appropriate to take a corrective action to address deviations from the documented protocols developed in Requirement R1.

M5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority that issued an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence that the issuer either: 1) confirmed that the response from the recipient of the Operating Instruction was correct; 2) reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver; or 3) took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. Such evidence could include, but is not limited to, dated and time-stamped voice recordings, or dated and time-stamped transcripts of voice recordings, or dated operator logs in fulfillment of Requirement R5.

M6. Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that was the recipient of an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence to show that the recipient either repeated, not necessarily verbatim, the Operating Instruction and received confirmation from the issuer that the response was correct, or requested that the issuer reissue the Operating Instruction in fulfillment of Requirement R6. Such evidence may include, but is not limited to, dated and time-stamped voice recordings (if the entity has such recordings), dated operator logs, an attestation from the issuer of the Operating Instruction, memos or transcripts.

M7. Each Balancing Authority, Reliability Coordinator and Transmission Operator that issued a written or oral single or multiple-party burst Operating Instruction during an Emergency shall provide evidence that the Operating Instruction was received by at least one receiver. Such evidence may include, but is not limited to, dated and time-stamped voice recordings (if the entity has such recordings), dated operator logs, electronic records, memos or transcripts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, and Transmission Operator shall each keep data or evidence for each applicable Requirement for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Additional Compliance Information

None

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Low	The responsible entity did not specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required in Requirement R1, Part 1.5 OR The responsible entity did not specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction, as required in Requirement R1, Part 1.6.	The responsible entity did not require the issuer and receiver of an oral or written Operating Instruction to use the English language, unless agreed to otherwise, as required in Requirement R1, Part 1.1. An alternate language may be used for internal operations.	The responsible entity did not include Requirement R1, Part 1.4 in its documented communication protocols.	The responsible entity did not include Requirement R1, Part 1.2 in its documented communications protocols OR The responsible entity did not include Requirement R1, Part 1.3 in its documented communications protocols OR The responsible entity did not develop any documented communications protocols as required in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	Low	N/A	N/A	An individual operator responsible for the Real-time operation of the interconnected Bulk Electric System at the responsible entity issued an Operating Instruction, prior to being trained on the documented communications protocols developed in Requirement R1.	An individual operator responsible for the Real-time operation of the interconnected Bulk Electric System at the responsible entity issued an Operating Instruction during an Emergency prior to being trained on the documented communications protocols developed in Requirement R1.
R3	Long-term Planning	Low	N/A	N/A	An individual operator at the responsible entity received an Operating Instruction prior to being trained.	An individual operator at the responsible entity received an Operating Instruction during an Emergency prior to being trained.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The responsible entity assessed adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions and provided feedback to those operating personnel and took corrective action, as appropriate AND The responsible entity assessed the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modified its documented communication	The responsible entity assessed adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, but did not provide feedback to those operating personnel OR The responsible entity assessed adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions and provided feedback to those operating personnel but did not take corrective action, as appropriate OR The responsible entity assessed the effectiveness of its documented communications protocols	The responsible entity did not assess adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions OR The responsible entity did not assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions.	The responsible entity did not assess adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions AND The responsible entity did not assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			protocols, as necessary AND The responsible entity exceeded twelve (12) calendar months between assessments.	in Requirement R1 for its operating personnel that issue and receive Operating Instructions, but did not modify its documented communication protocols, as necessary.		

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Real-time Operations	High	N/A	The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions: • Confirmed the receiver's response if the repeated information was correct (in accordance with Requirement R6). • Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver. • Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver.	N/A	The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions: • Confirmed the receiver's response if the repeated information was correct (in accordance with Requirement R6). • Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver. • Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. AND Instability, uncontrolled separation, or cascading failures occurred as a result.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Real-time Operations	High	N/A	The responsible entity did not repeat, not necessarily verbatim, the Operating Instruction during an Emergency and receive confirmation from the issuer that the response was correct, or request that the issuer reissue the Operating Instruction when receiving an Operating Instruction.	N/A	The responsible entity did not repeat, not necessarily verbatim, the Operating Instruction during an Emergency and receive confirmation from the issuer that the response was correct, or request that the issuer reissue the Operating Instruction when receiving an Operating Instruction AND Instability, uncontrolled separation, or cascading failures occurred as a result.
R7	Real-time Operations	High	N/A	The responsible entity that that issued a written or oral single-party to multiple-party burst Operating Instruction during an Emergency did not confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.	N/A	The responsible entity that that issued a written or oral single-party to multiple-party burst Operating Instruction during an Emergency did not confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction AND Instability, uncontrolled separation, or cascading failures occurred as a result.

E. Regional Variances

None

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	February 7, 2006	Adopted by Board of Trustees	Added measures and compliance elements
2	November 1, 2006	Adopted by Board of Trustees	Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Retired R1, R1.1, M1, M2 and updated the compliance monitoring information. Replaced R2 with new R1, R2 and R3.
2a	February 9, 2012	Interpretation of R2 adopted by Board of Trustees	Project 2009-22
3	November 7, 2012	Adopted by Board of Trustees	
4	May 6, 2014	Adopted by Board of Trustees	
4	April 16, 2015	FERC Order issued approving COM-002-4	

A. Introduction

1. **Title: Demand and Energy Data**

2. **Number: MOD-031-1**

3. **Purpose:** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Authority and Planning Coordinator (hereafter collectively referred to as the "Planning Coordinator")

   This proposed standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the proposed standard applies to both "Planning Authority" and "Planning Coordinator."

   4.1.2 Transmission Planner

   4.1.3 Balancing Authority

   4.1.4 Resource Planner

   4.1.5 Load-Serving Entity

   4.1.6 Distribution Provider

5. **Effective Date***

   5.1. MOD-031-1 shall become effective on the first day of the first calendar quarter that is twelve months after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   To ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, authority is needed to collect the applicable data.

   The collection of Demand, Net Energy for Load and Demand Side Management data requires coordination and collaboration between Planning Authorities (Planning Coordinators), Transmission and Resource Planners, Load-Serving Entities and

Distribution Providers. Ensuring that planners and operators have access to complete and accurate load forecasts – as well as the supporting methods and assumptions used to develop these forecasts – enhances the reliability of the Bulk Electric System. Consistent documenting and information sharing activities will also improve efficient planning practices and support the identification of needed system reinforcements. Furthermore, collection of actual Demand and Demand Side Management performance during the prior year will allow for comparison to prior forecasts and further contribute to enhanced accuracy of load forecasting practices.

B. Requirements and Measures

R1. Each Planning Coordinator or Balancing Authority that identifies a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data shall develop and issue a data request to the applicable entities in its area. The data request shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A list of Transmission Planners, Balancing Authorities, Load Serving Entities, and Distribution Providers that are required to provide the data ("Applicable Entities").

1.2. A timetable for providing the data. (A minimum of 30 calendar days must be allowed for responding to the request).

1.3. A request to provide any or all of the following actual data, as necessary:

1.3.1. Integrated hourly Demands in megawatts for the prior calendar year.

1.3.2. Monthly and annual integrated peak hour Demands in megawatts for the prior calendar year.

1.3.2.1. If the annual peak hour actual Demand varies due to weather-related conditions (e.g., temperature, humidity or wind speed), the Applicable Entity shall also provide the weather normalized annual peak hour actual Demand for the prior calendar year.

1.3.3. Monthly and annual Net Energy for Load in gigawatthours for the prior calendar year.

1.3.4. Monthly and annual peak hour controllable and dispatchable Demand Side Management under the control or supervision of the System Operator in megawatts for the prior calendar year. Three values shall be reported for each hour: 1) the committed megawatts (the amount under control or supervision), 2) the dispatched megawatts (the amount, if any, activated for use by the System Operator), and 3) the realized megawatts (the amount of actual demand reduction).

1.4. A request to provide any or all of the following forecast data, as necessary:

1.4.1. Monthly peak hour forecast Total Internal Demands in megawatts for the next two calendar years.

1.4.2. Monthly forecast Net Energy for Load in gigawatthours for the next two calendar years.

1.4.3. Peak hour forecast Total Internal Demands (summer and winter) in megawatts for ten calendar years into the future.

1.4.4. Annual forecast Net Energy for Load in gigawatthours for ten calendar years into the future.

1.4.5. Total and available peak hour forecast of controllable and dispatchable Demand Side Management (summer and winter), in megawatts, under the control or supervision of the System Operator for ten calendar years into the future.

1.5. A request to provide any or all of the following summary explanations, as necessary,:

1.5.1. The assumptions and methods used in the development of aggregated Peak Demand and Net Energy for Load forecasts.

1.5.2. The Demand and energy effects of controllable and dispatchable Demand Side Management under the control or supervision of the System Operator.

1.5.3. How Demand Side Management is addressed in the forecasts of its Peak Demand and annual Net Energy for Load.

1.5.4. How the controllable and dispatchable Demand Side Management forecast compares to actual controllable and dispatchable Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.

1.5.5. How the peak Demand forecast compares to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted.

M1. The Planning Coordinator or Balancing Authority shall have a dated data request, either in hardcopy or electronic format, in accordance with Requirement R1.

R2. Each Applicable Entity identified in a data request shall provide the data requested by its Planning Coordinator or Balancing Authority in accordance with the data request issued pursuant to Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each Applicable Entity shall have evidence, such as dated e-mails or dated transmittal letters that it provided the requested data in accordance with Requirement R2.

R3. The Planning Coordinator or the Balancing Authority shall provide the data collected under Requirement R2 to the applicable Regional Entity within 75 calendar days of receiving a request for such data, unless otherwise agreed upon by the parties. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each Planning Coordinator or Balancing Authority, shall have evidence, such as dated e-mails or dated transmittal letters that it provided the data requested by the applicable Regional Entity in accordance with Requirement R3.

R4. Any Applicable Entity shall, in response to a written request for the data included in parts 1.3-1.5 of Requirement R1 from a Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner with a demonstrated need for such data in order to conduct reliability assessments of the Bulk Electric System, provide or otherwise make available that data to the requesting entity. This requirement does not modify an entity's obligation pursuant to Requirement R2 to respond to data requests issued by its Planning Coordinator or Balancing Authority pursuant to Requirement R1. Unless otherwise agreed upon, the Applicable Entity: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- shall provide the requested data within 45 calendar days of the written request, subject to part 4.1 of this requirement; and
- shall not be required to alter the format in which it maintains or uses the data.

4.1. If the Applicable Entity does not provide data requested under this requirement because (1) the requesting entity did not demonstrate a reliability need for the data; or (2) providing the data would conflict with the Applicable Entity's confidentiality, regulatory, or security requirements, the Applicable Entity shall, within 30 calendar days of the written request, provide a written response to the requesting entity specifying the data that is not being provided and on what basis.

M4. Each Applicable Entity identified in Requirement R4 shall have evidence such as dated e-mails or dated transmittal letters that it provided the data requested or provided a written response specifying the data that is not being provided and the basis for not providing the data in accordance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Long-term Planning	Medium	N/A	N/A	N/A	The Planning Coordinator or Balancing Authority developed and issued a data request but failed to include either the entity(s) necessary to provide the data or the timetable for providing the data.
R2	Long-term Planning	Medium	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide all of the data requested in Requirement R1 part 1.5.1 through part 1.5.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide one of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide two of the requested items in Requirement R1 part	The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.3.1 through part 1.3.4 OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide three or more of the requested items in Requirement R1 part 1.4.1 through part 1.4.5

			did so after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 6 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	1.4.1 through part 1.4.5 OR The Applicable Entity, as defined in the data request developed in Requirement R1, provided the data requested in Requirement R1, but did so 11 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2 but prior to 15 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.	OR The Applicable Entity, as defined in the data request developed in Requirement R1, failed to provide the data requested in the timetable provided pursuant to Requirement R1 prior to 16 days after the date indicated in the timetable provided pursuant to Requirement R1 part 1.2.
R3	Long-term Planning	Medium	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, made available the data collected under Requirement R2, but	The Planning Coordinator or Balancing Authority, in response to a request by the Regional Entity, failed to make available the data collected under Requirement R2 prior to 91 days or more from the

			did so after 75 days from the date of request but prior to 81 days from the date of the request.	did so after 80 days from the date of request but prior to 86 days from the date of the request.	did so after 85 days from the date of request but prior to 91 days from the date of the request.	date of the request.
R4	Long-term Planning	Medium	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 45 days from the date of request but prior to 51 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 30 days of the written request but prior to 36 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 50 days from the date of request but prior to 56 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 35 days of the written request but prior to 41 days of the written resquest.	The Applicable Entity provided or otherwise made available the data to the requesting entity but did so after 55 days from the date of request but prior to 61 days from the date of the request OR The Applicable Entity that is not providing the data requested provided a written response specifying the data that is not being provided and on what basis but did so after 40 days of the written request but prior to 46 days of the written resquest.	The Applicable Entity failed to provide or otherwise make available the data to the requesting entity within 60 days from the date of the request OR The Applicable Entity that is not providing the data requested failed to provide a written response specifying the data that is not being provided and on what basis within 45 days of the written resquest.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	May 6, 2014	Adopted by the NERC Board of Trustees.	
1	February 19, 2015	FERC order approving MOD-031-1	

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Rationale for R1: To ensure that when Planning Coordinators (PCs) or Balancing Authorities (BAs) request data (R1), they identify the entities that must provide the data (Applicable Entity in part 1.1), the data to be provided (parts 1.3 – 1.5) and the due dates (part 1.2) for the requested data.

For Requirement R1 part 1.3.2.1, if the Demand does not vary due to weather-related conditions (e.g., temperature, humidity or wind speed), or the weather assumed in the forecast was the same as the actual weather, the weather normalized actual Demand will be the same as the actual demand reported for Requirement R1 part 1.3.2. Otherwise the annual peak hour weather normalized actual Demand will be different from the actual demand reported for Requirement R1 part 1.3.2.

Balancing Authorities are included here to reflect a practice in the WECC Region where BAs are the entity that perform this requirement in lieu of the PC.

Rationale for R2:

This requirement will ensure that entities identified in Requirement R1, as responsible for providing data, provide the data in accordance with the details described in the data request developed in accordance with Requirement R1. In no event shall the Applicable Entity be required to provide data under this requirement that is outside the scope of parts 1.3 - 1.5 of Requirement R1.

Rationale for R3:

This requirement will ensure that the Planning Coordinator or when applicable, the Balancing Authority, provides the data requested by the Regional Entity.

Rationale for R4:

This requirement will ensure that the Applicable Entity will make the data requested by the Planning Coordinator or Balancing Authority in Requirement R1 available to other applicable entities (Planning Coordinator, Balancing Authority, Transmission Planner or Resource Planner) unless providing the data would conflict with the provisions outlined in Requirement R4 below. The sharing of documentation of the supporting methods and assumptions used to develop forecasts as well as information-sharing activities will improve the efficiency of planning practices and support the identification of needed system reinforcements.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(ii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date*:**

   See the Implementation Plan for PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)

- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13,	Adopted by the NERC Board of	Replaced references to

	2014	Trustees	Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii)	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.
1.1(ii)	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-001-1.1(ii)	Modifications to adjust the applicability to owners of dispersed generation resources.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**

   Functional Entities:

   4.1 The Responsible Entity is:

   4.1.1 Eastern Interconnection – Planning Coordinator

   4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator

   4.1.3 Western Interconnection – Reliability Coordinator

   4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator

   4.2 Transmission Owner

   4.3 Generator Owner

5. **Effective Dates*:**

   See BC-specific PRC-002-2 Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.

1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.

M1. The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.

R3. Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1 Phase-to-neutral voltage for each phase of each specified BES bus.

3.2 Each phase current and the residual or neutral current for the following BES Elements:

3.2.1 Transformers that have a low-side operating voltage of 100kV or above.

3.2.2 Transmission Lines.

M3. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R4. Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1 A single record or multiple records that include:

- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
- At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.

4.2 A minimum recording rate of 16 samples per cycle.

4.3 Trigger settings for at least the following:

4.3.1 Neutral (residual) overcurrent.

4.3.2 Phase undervoltage or overcurrent.

M4. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.

R5. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:

5.1.1 Generating resource(s) with:

5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.

5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.

5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).

5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.

5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).

5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.

5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:

5.2.1 One BES Element; and

5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.

5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.

5.4 Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.

M5. The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator

Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

R6. Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

6.1 One phase-to-neutral or positive sequence voltage.

6.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.

6.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

6.4 Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.

M6. The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R7. Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

7.1 One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.

7.2 The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.

7.3 Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.

7.4 Frequency of at least one of the voltages in Requirement R7, Part 7.1.

M7. The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.

R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
o Eastern Interconnection	<59.75 Hz	>61.0 Hz
o Western Interconnection	<59.55 Hz	>61.0 Hz
o ERCOT Interconnection	<59.35 Hz	>61.0 Hz
o Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

o Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
o Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
o ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
o Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

R10. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

10.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.

10.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.

M10. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or 3) station drawings.

R11. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

11.1 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.

11.2 Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.

11.3 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.

11.4 FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.

11.5 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

M11. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.

R12. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- Restore the recording capability, or
- Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, Planning Coordinator, and Reliability Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	Long-term Planning	Lower	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part	The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own. OR The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days. OR The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by

			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

			OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.	OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.	OR The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.	The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days. OR The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days. OR The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.
R6	Long-term Planning	Lower	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the	The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.

			total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

R11	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority. OR The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data. OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in

			than 90 percent of the data but less than 100 percent of the data in the proper data format.	than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004).

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. <u>If there are no BES buses on the list:</u> the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

<u>If the list has 1 or more but less than or equal to 11 BES buses:</u> FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2

Sequence of Events Recording (SER) Data Format

(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State[1]

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

[1] "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO | GO			X		
R3	TO | GO				X	
R4	TO | GO				X	

Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation
R5	RE (PC | RC)	X	X	X	X
R6	TO			X	
R7	GO			X	
R8	TO | GO			X	
R9	TO | GO			X	

Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data	SER, FR, DDR Availability
R10	TO | GO	X		
R11	TO | GO		X	
R12	TO | GO			X

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Functional Entities:

When the term "Responsible Entity" is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT's data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:
The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:
The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads that connect the GSU transformer(s) to the Transmission System that are used exclusively to export energy directly from a BES generating unit or generating plant are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:
Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:
DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:
DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:
A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:
Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:
An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.
An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:
Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).
Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:
Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-

calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses "what" data is recorded, not "how" it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
   a. Only tangible substation or switchyard buses are included.
   b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
   - Electrically distant BES buses or electrically distant from other DME devices
   - Voltage sensitive areas
   - Cohesive load and generation zones
   - BES buses with a relatively high number of incident Transmission circuits
   - BES buses with reactive power devices
   - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

<u>Recording of Electrical Quantities</u>
For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

<u>Current Recordings</u>
The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.
Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current $\mathbf{I}_{r,}$ is calculated as a sum of vectors of three phase currents:
$\mathbf{I}_r = 3 \bullet \mathbf{I}_0 = \mathbf{I}_A + \mathbf{I}_B + \mathbf{I}_C$

$\mathbf{I}_0$ - Zero-sequence current

$\mathbf{I}_A$, $\mathbf{I}_B$, $\mathbf{I}_C$ - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

<u>Voltage Recordings</u>

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of ***why*** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings "greater than or equal to 500 MVA". The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT's judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires "One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs)." Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES

Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization…”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized…”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

A. Introduction

1. **Title: Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-5(i)

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.1.5 Protection Systems of individual dispersed power producing resources identified under Inclusion I4 of the BES definition where the Misoperations affected an aggregate nameplate rating of less than or equal to 75 MVA of BES Facilities.

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

   4.2.3 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

5. **Effective Date*:** See Project 2008-02.2 Implementation Plan.

[1] For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: High][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, DME records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	High	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	High	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	High	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	High	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	High	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	High	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1a	February 17, 2011	Adopted by NERC Board of Trustees	Project 2009-17 interpretation adding Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers

[2] (http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf).

Version	Date	Action	Change Tracking
1a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 1	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2	August 5, 2010	Adopted by NERC Board of Trustees	Project 2010-12 modifications to address Order No. 693 Directives contained in paragraph 1469
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	FERC's Order approving the interpretation of R1 and R3 is effective as of September 26, 2011
2.1a	February 9, 2012	Adopted by NERC Board of Trustees	Errata change under Project 2010-07 to add "…and generator interconnection Facility…"
3	August 14, 2014	Adopted by NERC Board of Trustees	Revision under Project 2010-05.1
4	November 13, 2014	Adopted by NERC Board of Trustees	Applicability revision under Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
5	May 7, 2015	Adopted by NERC Board of Trustees	Revision under Project 2008-02.2
5(i)	June 22, 2015	Adopted by NERC Board of Trustees	Revision to VRF designations from "Medium" to "High" for Requirements R1 through R6, in compliance with the Federal Energy Regulatory Commission's directive in N. Am. Elec. Reliability Corp., 151 FERC ¶ 61,129 (2015)

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection

[3] (http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf).
[4] "2011 Risk Assessment of Reliability Performance." NERC. (http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011). Pg. 3.
[5] "State of Reliability 2014." NERC. (http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx). May 2014. Pg. 18 of 106.
[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
3. ***Slow Trip – During Fault*** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** – *An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.
>
> **Example 1e:** The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.
>
> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

> **Example 3a:** A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

> **Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or DME would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). April 1, 2013. Pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[8]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013. (http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf). Figure 15: NERC Wide Misoperations by Cause Code. Pg. 22 of 40.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

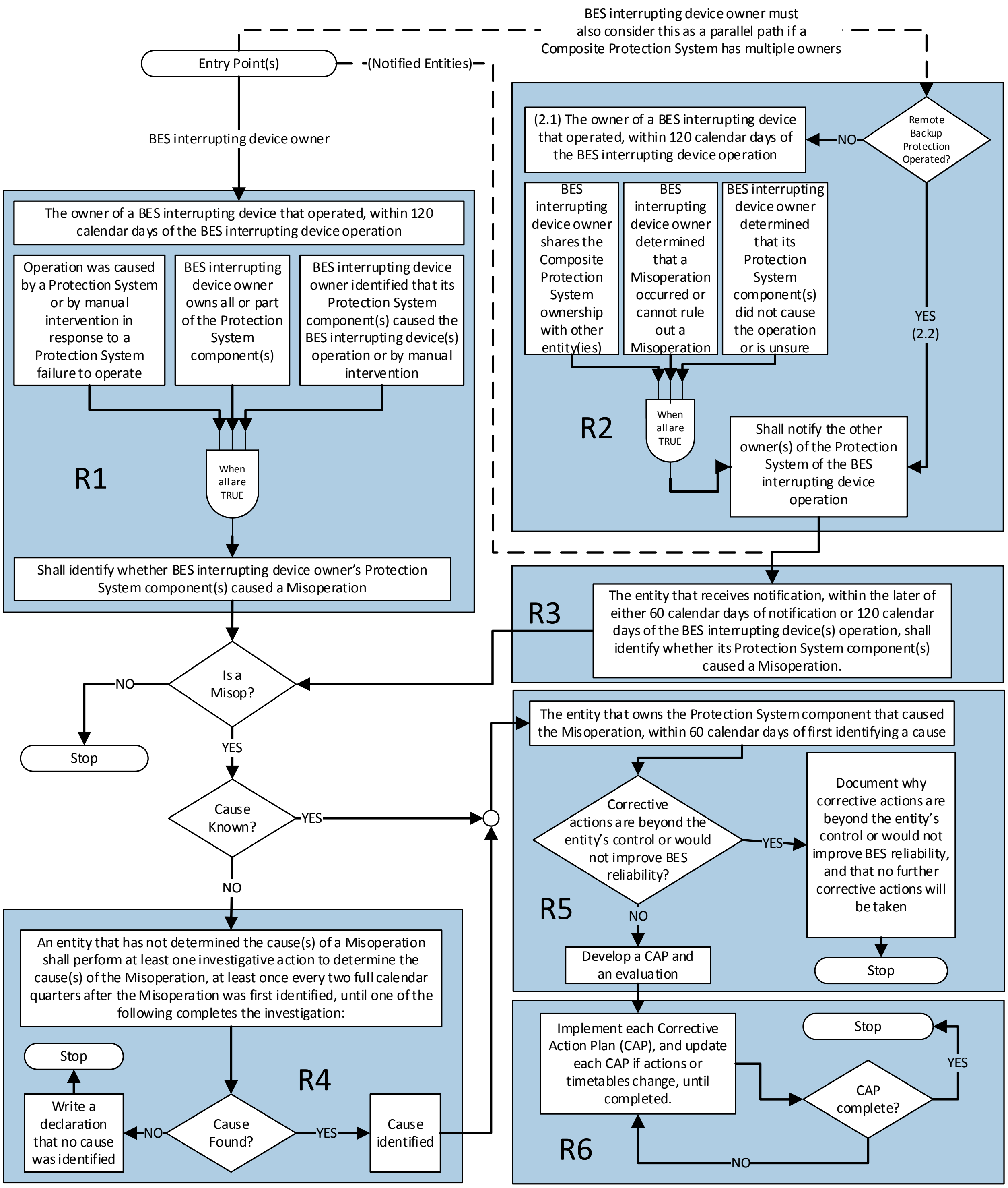
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Introduction

The only revisions made to version of PRC-004-4 are revisions to section 4.2 Facilities to clarify applicability of the Requirements of the standard at generator Facilities. These applicability revisions are intended to clarify and provide for consistent application of the Requirements to BES generator Facilities included in the BES through Inclusion I4 – Dispersed Power Producing Resources.

Rationale for Applicability

Misoperations occurring on the Protection Systems of individual generation resources identified under Inclusion I4 of the BES definition do not have a material impact on BES reliability when considered individually; however, the aggregate capability of these resources may impact BES reliability if a number of Protection Systems on the individual power producing resources incorrectly operated or failed to operate as designed during a system event. To recognize the potential for the Protection Systems of individual power producing resources to affect the reliability of the BES, 4.2.1.5 of the Facilities section reflects the threshold consistent with the revised BES definition. See FERC Order Approving Revised Definition, P 20, Docket No. RD14-2-000. The intent of 4.2.1.5 of the Facilities section is to exclude from the standard requirements these Protection Systems for “common- mode failure” type scenarios affecting less than or equal to 75 MVA aggregated nameplate generating capability at these dispersed generating facilities.

A. Introduction

1. **Title:** **Protection System Maintenance**

2. **Number:** PRC-005-2(i)

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

   4.2. Facilities:

   4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection Systems installed as a Special Protection System (SPS) for BES reliability.

   4.2.5 Protection Systems for the following BES generator Facilities for generators not identified through Inclusion I4 of the BES definition:

   4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

   4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.

   4.2.5.3 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

   4.2.6 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

   4.2.6.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.

5. **Effective Date*:** See BC-specific PRC-005-2 Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

1.1. Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

1.2. Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The responsible entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)
R2	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to:

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	February 7, 2006	Adopted by NERC Board of Trustees	1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2
1a	February 17, 2011	Adopted by NERC Board of Trustees	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17
1b	November 5, 2009	Adopted by NERC Board of Trustees	Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10
1b	February 3, 2012	FERC order approving revised definition of “Protection System”	Per footnote 8 of FERC’s order, the definition of “Protection System” supersedes interpretation “b” of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013) *See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012)
1.1b	May 9, 2012	Adopted by NERC Board of Trustees	Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility

Version	Date	Action	Change Tracking
2	November 7, 2012	Adopted by NERC Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Approved by NERC Standards Committee	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. (no change to standard version number)
2	March 7, 2014	Adopted by NERC Board of Trustees	Modified R1 VSL in response to FERC directive (no change to standard version number)
2(i)	November 13, 2014	Adopted by NERC Board of Trustees	Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources
2(i)	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-005-2(i)	

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[1]**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

[1] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval[1]**	**Maintenance Activities**
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 calendar months	Verify that the communications system is functional.
	6 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 calendar years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using **Vented Lead-Acid (VLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **with Valve Regulated Lead-Acid (VRLA) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	6 Calendar Months	Inspect: • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Physical condition of battery rack
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) **Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries** **Excluding distributed UFLS and distributed UVLS (see Table 3)** Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) **Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 calendar years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. Alarming for power supply failure (See Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.
Voltage and/or current sensing devices associated with UFLS or UVLS	12 calendar	Verify that current and/or voltage signal values are provided to

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	**Maximum Maintenance Interval**	**Maintenance Activities**
systems.	years	the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 calendar years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 calendar years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 calendar years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

Application Guidelines

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for 4.2.5

In order to differentiate between typical BES generator Facilities and BES generators at dispersed power producing facilities, section 4.2.5 was separated into two sections (4.2.5 and 4.2.6). The applicability to non-dispersed power producing Facilities has been maintained and can be found in 4.2.5. The applicability to dispersed power producing Facilities has been modified and relocated from 4.2.5 to 4.2.6.

Rationale for 4.2.6:

Applicability of the Requirements of PRC-005-2 to dispersed power producing resources is separated out in section 4.2.6. The intent is that for such resources, the Requirements would apply only to Protection Systems on equipment used in aggregating the BES dispersed power producing resources from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or higher including the Protection Systems for those transformers used in aggregating generation.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-2

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. **Effective Date*:**

   This standard is effective on the first day of the first calendar quarter six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

   PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
- Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
- Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per

Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation , including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. OR The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.	The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.
R2	N/A	The Planning Coordinator identified an island(s) to	The Planning Coordinator identified an island(s) to serve	The Planning Coordinator identified an island(s) to serve

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.	as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3. OR The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.
R3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions. OR The Planning Coordinator failed to develop a UFLS program

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR The Planning Coordinator failed to provide its UFLS database to

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by the

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.	assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.	evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.
R15	N/A	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a	The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, but failed to develop a Corrective Action Plan and a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.	schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.	schedule for implementation by the UFLS entities within its area. OR The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

D.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

DA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

DA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

DA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through DA3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 but simulation failed to include one (1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include two (2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D3 but simulation failed to include all of the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR The Planning Coordinator failed

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.1	N/A	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands OR The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands	The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.B.2	N/A	N/A	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2	The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2 OR The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
D.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in simulations of underfrequency

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		conditions		conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
D.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4.7.			OR The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2
D.B.11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.	D.B.11.1 and D.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.	D.B.11.1 and D.B.11.2 within a time greater than 15 months of actuation. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2. OR The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.
D.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in and document a coordinated UFLS design assessment of the

D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies

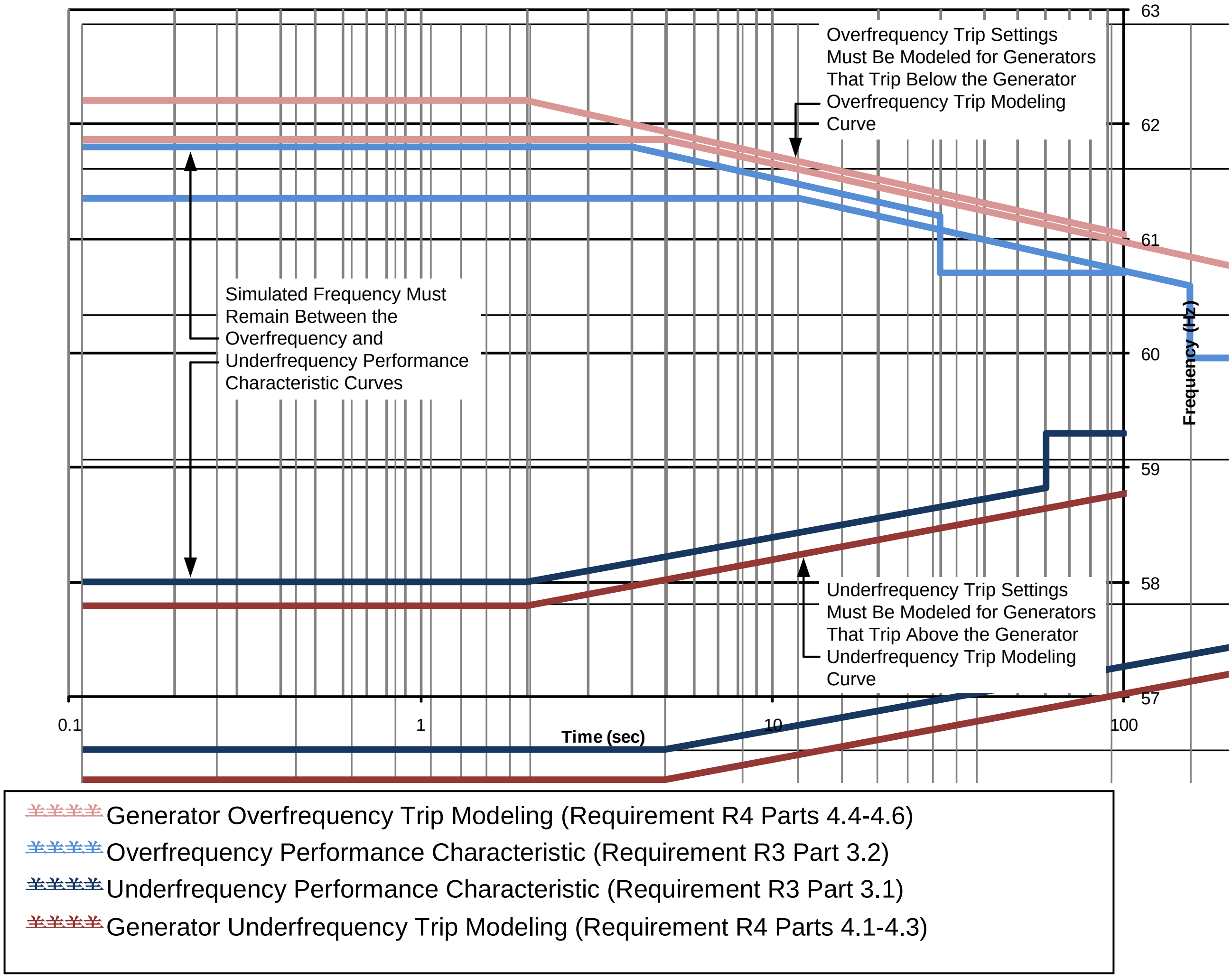
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-2 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6

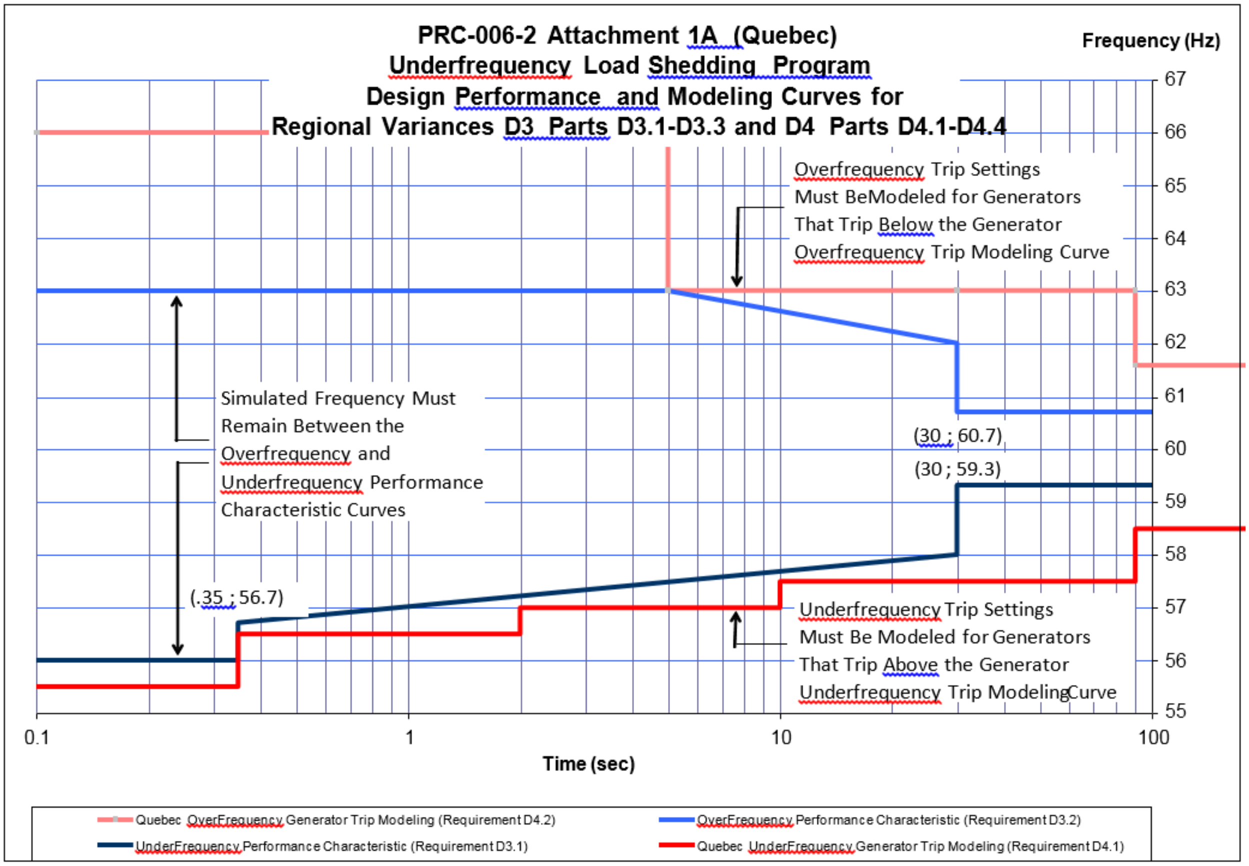


Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-2 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D3 Parts D3.1-D3.3 and D4 Parts D4.1-D4.4
Frequency (Hz)
67
66
65
64
63
62
61
60
59
58
57
56
55
Overfrequency Trip Settings
Must BeModeled for Generators
That Trip Below the Generator
Overfrequency Trip Modeling Curve
Simulated Frequency Must
Remain Between the
Overfrequency and
Underfrequency Performance
Characteristic Curves
(30 ; 60.7)
(30 ; 59.3)
(.35 ; 56.7)
Underfrequency Trip Settings
Must Be Modeled for Generators
That Trip Above the Generator
Underfrequency Trip ModelingCurve
0.1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement D4.2)
OverFrequency Performance Characteristic (Requirement D3.2)
UnderFrequency Performance Characteristic (Requirement D3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D4.1)

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R9:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:

The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

5. **Effective Date*:** See Project 2008-02.2 Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The applicable entity shall retain documentation as evidence for six calendar years.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	High	N/A	N/A	N/A	The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Long-term Planning	High	N/A	N/A	The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2. OR The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.	The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.
R3	Long-term Planning	Medium	N/A	N/A	N/A	The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Medium	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.	The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event. OR The applicable entity failed to perform an assessment in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days. OR The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	Operations Planning	Lower	The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days. OR The applicable entity failed to update the database in accordance with Requirement R6.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	Operations Planning	Lower	The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule. OR The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.	The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule. OR The applicable entity failed to provide data in accordance with Requirement R7.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Planning	Lower	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.	The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days. OR The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2	May 7, 2015	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.
2	November 19, 2015	FERC Letter Order issued approving PRC-010-2. Docket RD15-5-000	

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, "Undervoltage Load Shedding Program" or "UVLS Program" includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

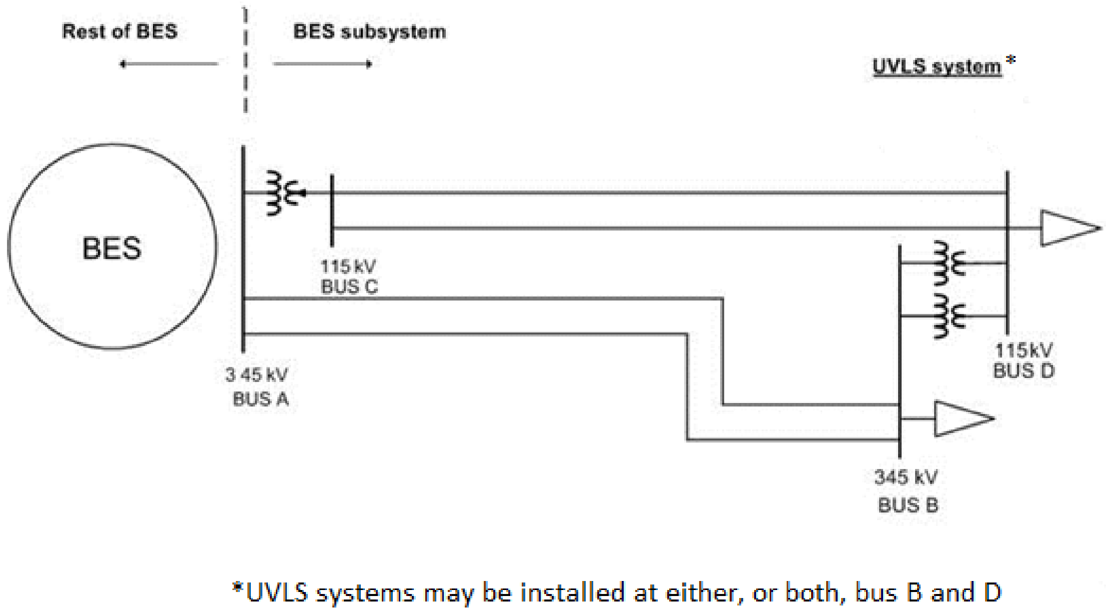


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC- 006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause

[3] Id.

of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The "within three calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well-accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires

[4] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[8] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).

that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

[9] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).
[10] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or

[12] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).
[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).
[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
[16] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners

[19] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).
[20] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).
[21] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding).
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

2. **Number:** PRC-019-2

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

   For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

   4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.2 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

   4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

   4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

   4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date*:**

   See the Implementation Plan for PRC-019-2.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[1] limiters and protection functions) with the applicable

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

D. Compliance

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,”Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

"Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

"IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-019-2	Modifications to adjust the applicability to owners of dispersed generation resources.

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$C = V^2_g/2*(1/X_s-1/X_d)$

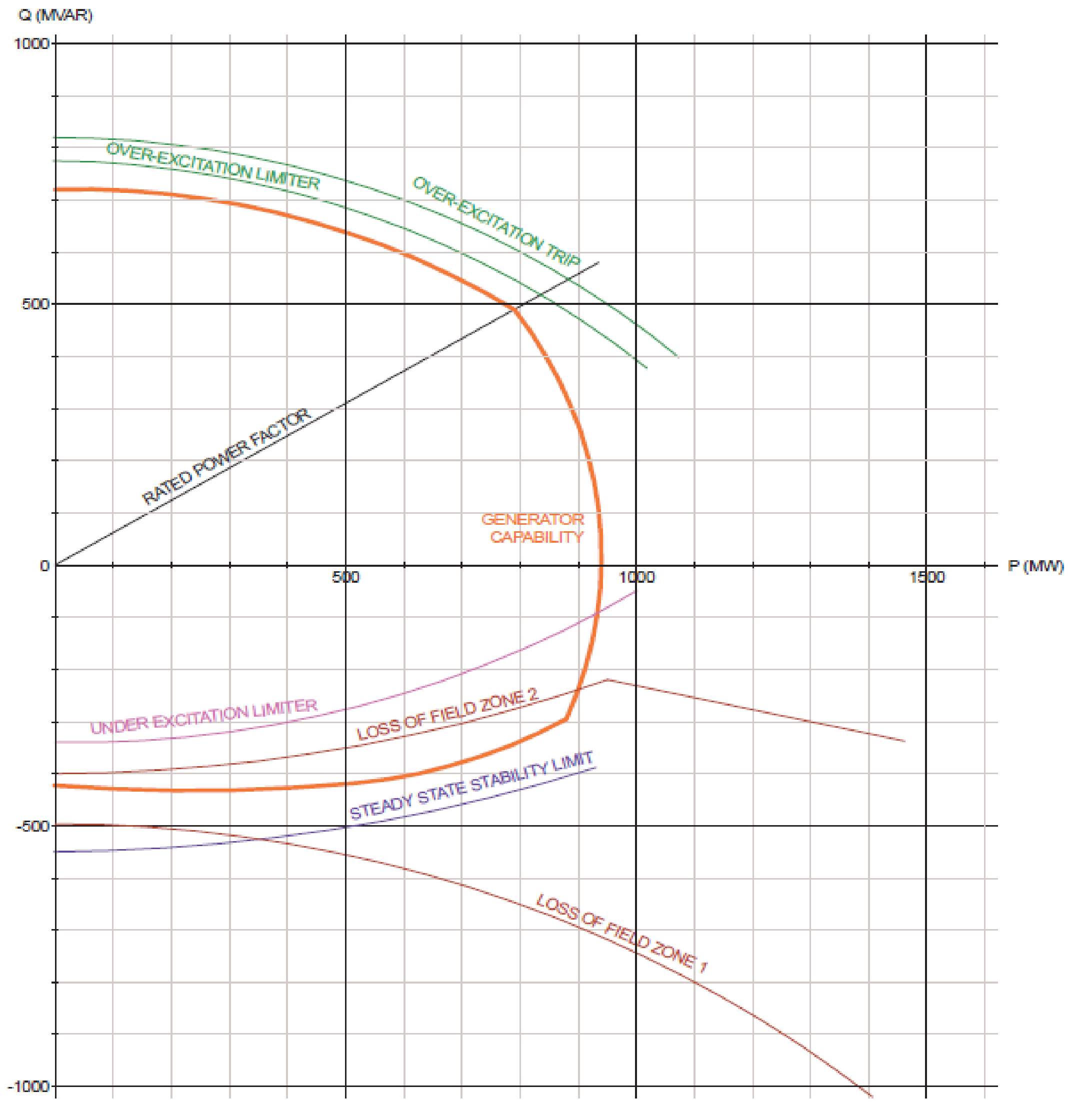
$R = V^2_g/2*(1/X_s+1/X_d)$

On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

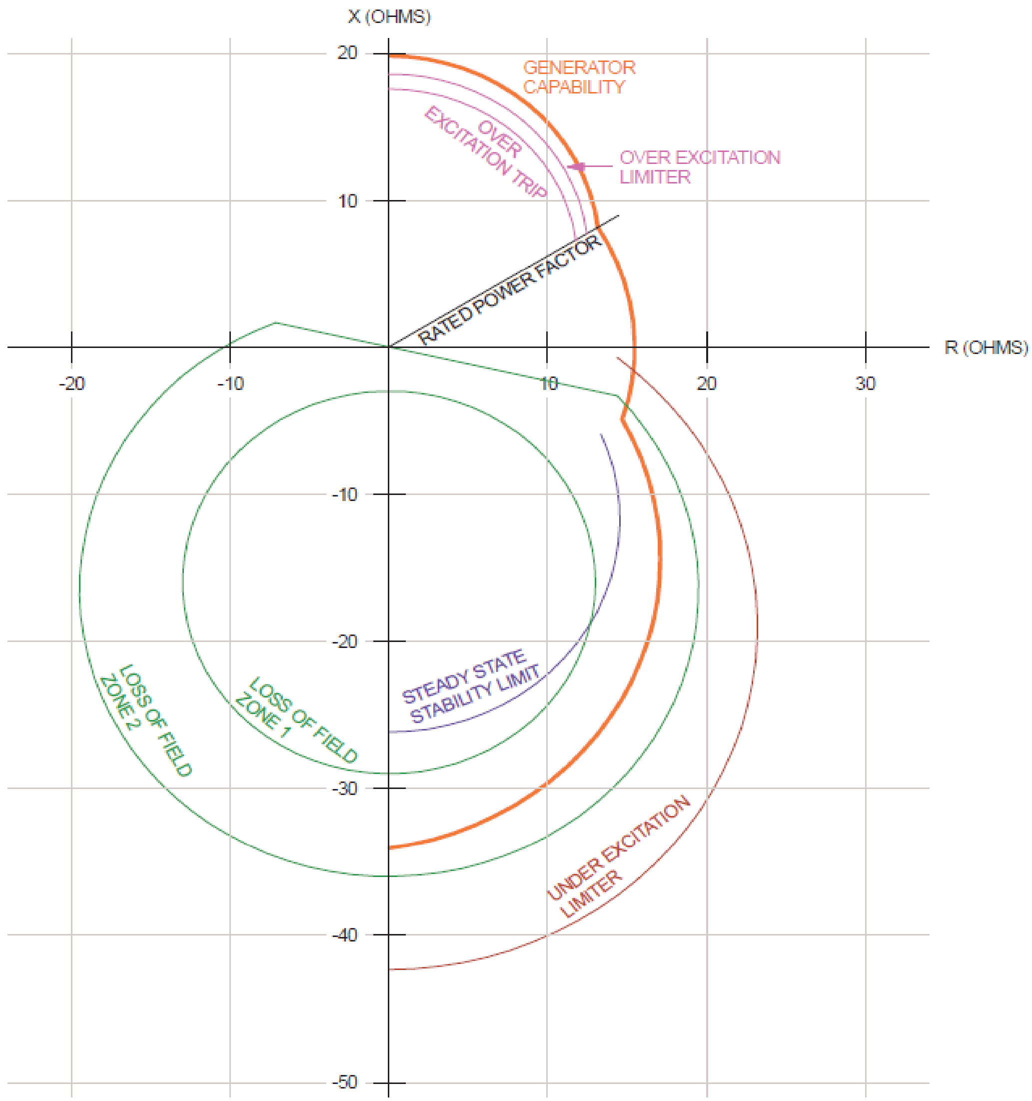
$C = (X_d-X_s)/2$

$R = (X_d+X_s)/2$

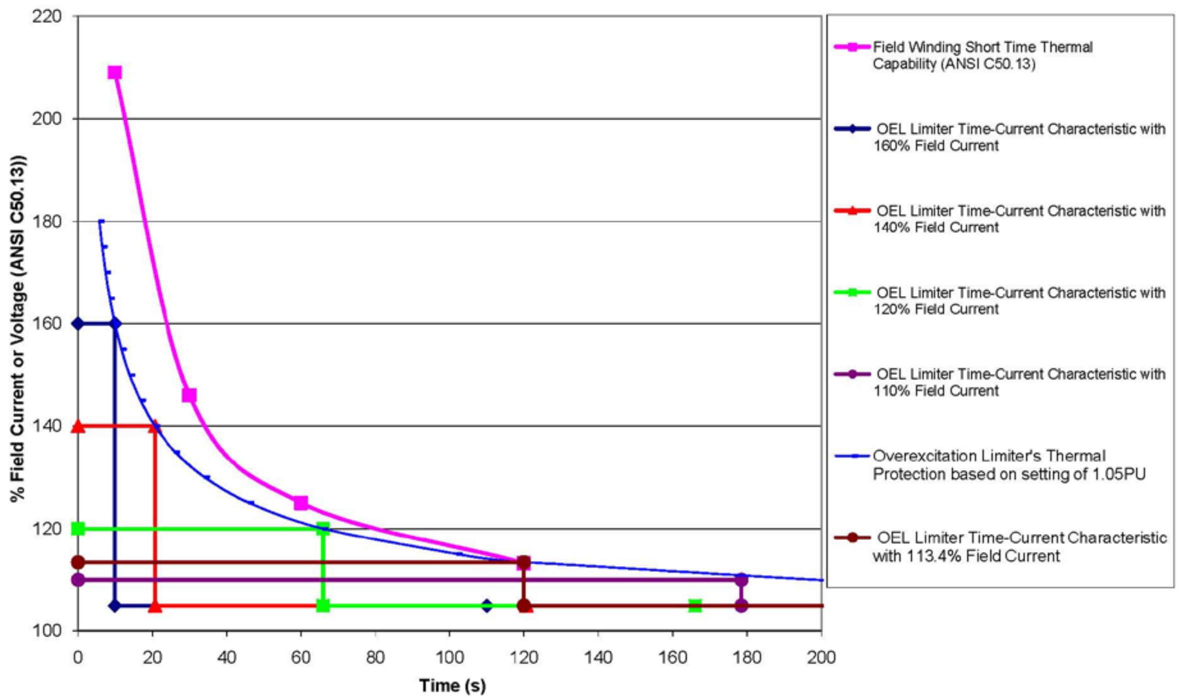
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
   4.1. Generator Owner
5. **Effective Date*:**
   See the Implementation Plan for PRC-024-2.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[2] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[3]) caused by an event on the

[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[4] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[5] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[5] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

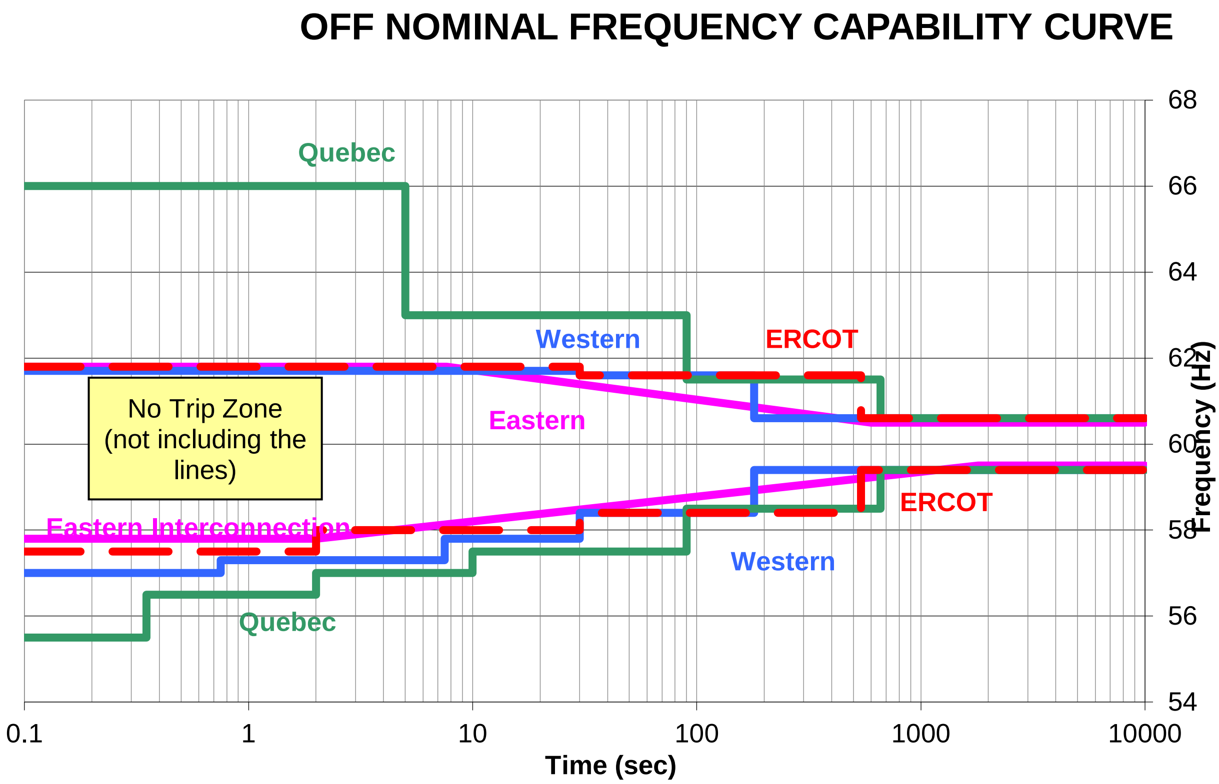
Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

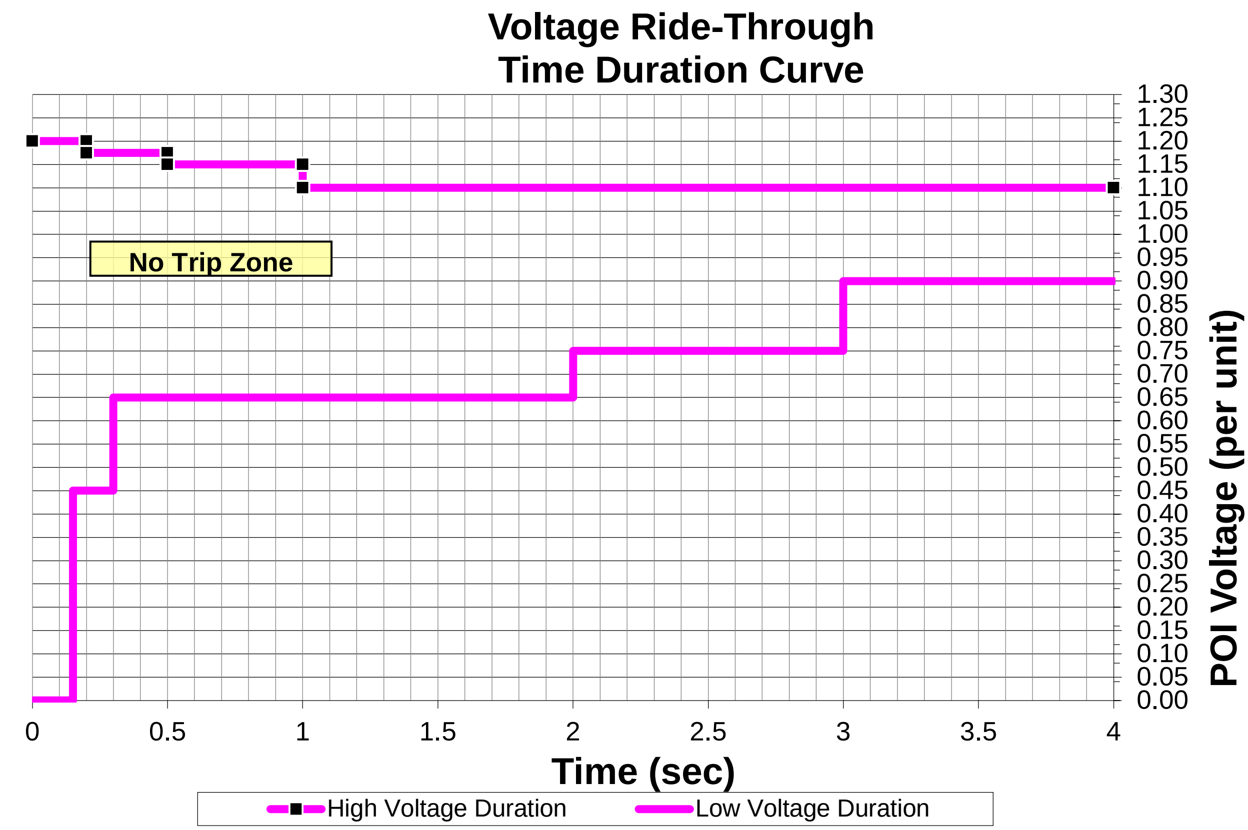
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4.1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date*:**

   5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operational Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power Schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The British Columbia Utilities Commission.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures 1 through 6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operational Planning**	**High**	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	**Real-time Operations, Same-day Operations, and Operational Planning**	**High**	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	**Real-time Operations, Same-day Operations, and Operational Planning**	**High**	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15 Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

E.A.16 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.17 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

E.A.18.1. Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures[1]

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	voltage schedules.	voltage schedules.	the voltage schedules.	
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage Schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-4
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates***

   See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

2.2. When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

2.3. Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

5.1. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

M5. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

6.1. If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The British Columbia Utilities Commission.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources.	Revised

4	11/13/2014	Adopted by NERC Board of Trustees	
4	5/29/2015	FERC Letter Order in Docket No. RD15-3-000 approving VAR-002-4	

Guidelines and Technical Basis

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R3:

This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

Rationale for R5:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

Rationale for Exclusion in R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR- 002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

Rationale for R6:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.

A. Introduction

1. **Title:** **Automatic Voltage Regulators (AVR)**

2. **Number:** VAR-002-WECC-2

3. **Purpose:** To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage.

4. **Applicability**

   4.1. Generator Operators

   4.2. Transmission Operators that operate synchronous condensers

   4.3. This VAR-002-WECC-2 Standard only applies to synchronous generators and synchronous condensers that are connected to the Bulk Electric System.

5. **Effective Date*:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall have AVR in service and in automatic voltage control mode 98% of all operating hours for synchronous generators or synchronous condensers. Generator Operators and Transmission Operators may exclude hours for R1.1 through R1.10 to achieve the 98% requirement. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R1.1. The synchronous generator or synchronous condenser operates for less than five percent of all hours during any calendar quarter.

R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.

R1.3. AVR exhibits instability due to abnormal system configuration.

R1.4. Due to component failure, the AVR may be out of service up to 60 consecutive days for repair per incident.

R1.5. Due to a component failure, the AVR may be out of service up to one year provided the Generator Operator or Transmission Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.

R1.6. Due to a component failure, the AVR may be out of service up to 24 months provided the Generator Operator or Transmission Operator submits documentation identifying the need for time for excitation system replacement (replace the AVR, limiters, and controls but not necessarily the power source and power bridge) and to schedule an outage.

R1.7. The synchronous generator or synchronous condenser has not achieved Commercial Operation.

R1.8. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the AVR is unavailable for service.

R1.9. The Reliability Coordinator directs Transmission Operator to operate the synchronous condenser, and the AVR is unavailable for service.

R1.10. If AVR exhibits instability due to operation of a Load Tap Changer (LTC) transformer in the area, the Transmission Operator may authorize the Generator Operator to operate the excitation system in modes other than automatic voltage control until the system configuration changes.

C. Measures

M1. Generator Operators and Transmission Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator and synchronous condenser of the following:

M1.1 The actual number of hours the synchronous generator or synchronous condenser was on line.

M1.2 The actual number of hours the AVR was out of service.

M1.3 The AVR in service percentage.

M1.4 If excluding AVR out of service hours as allowed in R1.1 through R1.10, provide:

M1.4.1 The number of hours excluded,

M1.4.2 The adjusted AVR in-service percentage,

M1.4.3 The date of the outage.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly

- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators and Transmission Operators shall keep evidence for Measures M1 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.9 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.4 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the in-service percentages, do not include the time the AVR is out of service due to R1.1 through R1.10.

1.4.4 The standard shall be applied on a machine-by-machine basis (a Generator Operator or Transmission Operator can be subject to a separate sanction for each non-compliant synchronous generator and synchronous condenser).

E. Regional Differences

None

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operational Assessment	Medium	There shall be a Lower Level of non-compliance if AVR is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.	There shall be a Moderate Level of non-compliance if AVR is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.	There shall be a High Level of non-compliance if AVR is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.	There shall be a Severe Level of non-compliance if AVR is in service less than 70% of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002a-1	
1	April 21, 2011	FERC Order issued approving VAR-002-WECC-1 (FERC approval effective June 27, 2011; Effective Date July 1, 2011)	
2	November 13, 2014	Adopted by NERC Board of Trustees	
2	March 3, 2015	FERC letter order approving VAR-002-WECC-2	

A. Introduction

1. **Title: Power System Stabilizer (PSS)**

2. **Number:** VAR-501-WECC-2

3. **Purpose:** To ensure that Power System Stabilizers (PSS) on synchronous generators shall be kept in service.

4. **Applicability:**

   4.1. Generator Operators

5. **Effective Date*:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators shall have PSS in service 98% of all operating hours for synchronous generators equipped with PSS. Generator Operators may exclude hours for R1.1 through R1.12 to achieve the 98% requirement. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R1.1. The synchronous generator operates for less than five percent of all hours during any calendar quarter.

R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.

R1.3. PSS exhibits instability due to abnormal system configuration.

R1.4. Unit is operating in the synchronous condenser mode (very near zero real power level).

R1.5. Unit is generating less power than its design limit for effective PSS operation.

R1.6. Unit is passing through a range of output that is a known "rough zone" (range in which a hydro unit is experiencing excessive vibration).

R1.7. The generator AVR is not in service.

R1.8. Due to component failure, the PSS may be out of service up to 60 consecutive days for repair per incident.

R1.9. Due to a component failure, the PSS may be out of service up to one year provided the Generator Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.

R1.10. Due to a component failure, the PSS may be out of service up to 24 months provided the Generator Operator submits documentation identifying the need for time for PSS replacement and to schedule an outage.

R1.11. The synchronous generator has not achieved Commercial Operation.

R1.12. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the PSS is unavailable for service.

C. Measures

M1. Generators Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator of the following:

M1.1 The number of hours the synchronous generator was on line.

M1.2 The number of hours the PSS was out of service with generator on line.

M1.3 The PSS in service percentage

M1.4 If excluding PSS out of service hours as allowed in R1.1 through R1.12, provide:

M1.4.1 The number of hours excluded,

M1.4.2 The adjusted PSS in-service percentage,

M1.4.3 Date of the outage.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly

- Spot check audits conducted anytime with 30 days notice

- Periodic audit as scheduled by the Compliance Enforcement Authority

- Investigations

- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators shall keep evidence for Measures M1 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.12 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.8 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the adjusted in-service percentage, the PSS out of service hours do not include the time associated with R1.1 through R1.12.

1.4.4 The standard shall be applied on a generating unit by generating unit basis (a Generator Operator can be subject to a separate sanction for each non- compliant synchronous generating unit or to a single sanction for multiple machines that operate as one unit).

E. Regional Differences

None

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operational Assessment	Medium	There shall be a Lower Level of non-compliance if PSS is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.	There shall be a Moderate Level of non-compliance if PSS is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.	There shall be a High Level of non-compliance if is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.	There shall be a Severe Level of non-compliance if PSS is in service less than 70% of all hours during which the synchronous generating unit is on line for each calendar quarter.

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002b-1	
1	October 28, 2008	Adopted by NERC Board of Trustees	
1	April 21, 2011	FERC Order issued approving VAR-501-WECC-1 (FERC approval effective June 27, 2011; Effective Date July 1, 2011)	
2	November 13, 2014	Adopted by NERC Board of Trustees	
2	March 3, 2015	FERC letter order approved VAR-501-WECC-2	