British Columbia Utilities Commission

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ORDER NUMBER
R-19-24

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. 17

BEFORE:
E. B. Lockhart, Panel Chair
E. A. Brown, Commissioner

on July 16, 2024

ORDER

WHEREAS:

A. On April 26, 2024, pursuant to section 125.2(3) of the *Utilities Commission Act* (UCA), British Columbia Hydro and Power Authority (BC Hydro) submitted to the British Columbia Utilities Commission (BCUC) Mandatory Reliability Standards (MRS) Assessment Report No. 17 (Report) assessing six new and revised reliability standards (Revised Standards) and three new terms (Glossary Terms) from the North American Electric Reliability Corporation (NERC) Glossary of Terms dated March 8, 2023 (NERC Glossary). BC Hydro recommends that four Revised Standards be adopted in BC;

B. BC Hydro states that two Revised Standards EOP-011-3 and EOP-012-1 are not recommended for adoption as they will not be effective in the U.S. until the Federal Energy Regulatory Commission (FERC) approves EOP-012-2 as a replacement for EOP-012-1. The three Glossary Terms are associated solely with this revised standard and are also not recommended for adoption at this time;

C. Further, BC Hydro recommends that one implementation plan approved by FERC related to the Revised Standards be adopted with revisions in BC (BC-specific Implementation Plan);

D. BC Hydro states that it did not assess compliance-related provisions (Compliance Provisions) in the standards because they are not mandatory reliability standard requirements;

E. By Order R-15-24 dated June 5, 2024, the BCUC established a regulatory timetable and a written comment process for the review of the Report and directed BC Hydro to make the Report available on its external website and to notify all entities registered in the British Columbia MRS Program (Registered Entities) of the review process;

F. On June 27, 2024, FortisBC Inc. (FBC) submitted a letter of comment stating that its feedback is reflected in the Report and has no additional comments;

G. On July 11, 2024, BC Hydro filed its response to FBC's letter of comment;

H. The BCUC has not reviewed the recoverability of the estimated costs to adopt the Revised Standards and Revised Terms;

I. Pursuant to section 125.2(6) of the UCA, the BCUC must adopt the reliability standards addressed in the report if the BCUC considers that the reliability standards are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliability standards, unless the BCUC determines under section 125.2(7), after a hearing, that the reliability standard is not in the public interest;

J. The BCUC has reviewed and considered the Report, the Revised Standards and the Glossary Terms assessed therein, and comments received from FBC and determines that adoption of the recommendations in the Report is warranted, with the BC-specific Implementation Plan; and

K. Although not assessed by BC Hydro, the BCUC finds 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. The BCUC also considers it appropriate to provide effective dates for BC Registered Entities to come into compliance with the Revised Standards adopted in this order.

NOW THEREFORE pursuant to sections 125.2(3) and 125.2(6) of the UCA, the BCUC orders as follows:

1. Revised Standards CIP-003-9, IRO-010-5, PRC-002-4 and TOP-003-6.1 assessed in the Report are adopted with effective dates as identified in Attachment A to this order.

2. Each standard to be superseded by a Revised Standard adopted in this order shall remain in effect until the effective date of the Revised Standard superseding it.

3. Revised Standards EOP-011-3 and EOP-012-1 and the Glossary Terms (Generator Cold Weather Critical Component, Extreme Cold Weather Temperature and Generator Cold Weather Reliability Event) assessed in the Report are held in abeyance and are of no force or effect in BC until the BCUC determines otherwise.

4. All reliability standards listed in Attachment A to this order are effective in BC as of the dates shown. The effective dates for the reliability standards listed in Attachment A supersede the effective dates that were included in any similar list appended to any previous order of the BCUC.

5. Individual requirements and requirement parts in reliability standards that incorporate by reference reliability standards that have not been adopted by the BCUC are of no force or effect in BC, and individual requirements or requirement parts in reliability standards that the BCUC has adopted but for which the BCUC has not determined an effective date, are of no force or effect in BC.

6. Defined terms in the reliability standards bear the same meanings as those in the NERC Glossary dated March 8, 2023. Terms in the NERC Glossary, which do not include a FERC approval effective date on or before November 30, 2023, are of no force or effect in BC.

7. All NERC Glossary terms listed in Attachment B to this order are in effect in BC as of the effective dates indicated.

8. The Compliance Provisions that accompany each of the adopted reliability standards are adopted by the BCUC.

9. The BC-specific Implementation Plan for CIP-003-9 is adopted and the standard is effective on the date in the standard as set out in Attachment C to this order.

10. With the exception of Revised Standards EOP-011-3 and EOP-012-1, the Revised Standards in their written form are adopted as set out in Attachment D to this order.

11. The Revised Standards and BC-specific Implementation Plan adopted in BC by the BCUC are to be posted by the Western Electricity Coordinating Council (WECC) on its website with a link from the BCUC website.

12. Entities subject to MRS adopted in BC must report to the BCUC and may, on a voluntary basis, report to NERC or to FERC.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of July 2024.

BY ORDER

Original signed by:

E. B. Lockhart
Commissioner

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

Standard	Name	BCUC Order Adopting	Effective Date
BAL-001-2	Real Power Balancing Control Performance	R-14-16	July 1, 2016
BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	R-21-19	April 1, 2020
BAL-002-WECC-3	Contingency Reserve	R-34-22A1	October 29, 2022
BAL-003-2	Frequency Response and Frequency Bias Setting	R-21-21	October 1, 2021
BAL-004-WECC-3	Automatic Time Error Correction	R-21-19	January 1, 2020
BAL-005-1	Balancing Authority Control	R-33-18	October 1, 2019
CIP-002-5.1a	Cyber Security — BES Cyber System Categorization	R-33-18	October 1, 2018 and as per BC-specific Implementation Plan
CIP-003-8[1]	Cyber Security — Security Management Controls	R-19-20	October 1, 2020 and as per BC-specific Implementation Plan
CIP-003-9	Cyber Security — Security Management Controls	R-19-24	October 1, 2027 and as per BC-specific Implementation Plan
CIP-004-6[1]	Cyber Security — Personnel & Training	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-004-7	Cyber Security — Personnel & Training	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
CIP-005-6[1]	Cyber Security – Electronic Security Perimeter(s)	R-19-20	April 1, 2023 and as per BC-specific Implementation Plan
CIP-005-7	Cyber Security – Electronic Security Perimeter(s)	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan

[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.

Standard	Name	BCUC Order Adopting	Effective Date
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-007-6	Cyber Security — System Security Management	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-008-6	Cyber Security – Incident Reporting and Response Planning	R-19-20	April 1, 2023
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems	R-39-17	October 1, 2018 and as per BC-specific Implementation Plan
CIP-010-3[1]	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-19-20	April 1, 2023 and as per BC-specific Implementation Plan
CIP-010-4	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
CIP-011-2[1]	Cyber Security – Information Protection	R-39-17	October 1, 2018 and as BC-specific Implementation Plan
CIP-011-3	Cyber Security – Information Protection	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
CIP-012-1	Cyber Security – Communications between Control Centers	R-21-21	October 1, 2023
CIP-013-1[1]	Cyber Security - Supply Chain Risk Management	R-19-20	April 1, 2023 and as per BC-specific Implementation Plan
CIP-013-2	Cyber Security - Supply Chain Risk Management	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
CIP-014-3	Physical Security	R-44-23	September 8, 2023
COM-001-3	Communications	R-39-17	R1, R2: October 1, 2017 R3-R13: October 1, 2018
COM-002-4	Operating Personnel Communications Protocols	R-32-16A	April 1, 2017

Standard	Name	BCUC Order Adopting	Effective Date
EOP-003-1[2]	Load Shedding Plans	G-67-09	November 1, 2010
EOP-003-2[3]	Load Shedding Plans	N/A	Adoption held in abeyance at this time[4]
EOP-004-4	Event Reporting	R-21-19	October 1, 2020
EOP-005-3	System Restoration from Blackstart Resources	R-21-19	October 1, 2020
EOP-006-3	System Restoration Coordination	R-21-19	October 1, 2020
EOP-008-2	Loss of Control Center Functionality	R-21-19	October 1, 2020
EOP-010-1	Geomagnetic Disturbance Operations	R-38-15	R1, R3: October 1, 2016 R2: October 1, 2017
EOP-011-1[1]	Emergency Operations	R-39-17	October 1, 2018
EOP-011-2	Emergency Preparedness and Operations	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
EOP-011-3	Emergency Operations	N/A	Adoption held in abeyance at this time
EOP-012-1	Extreme Cold Weather Preparedness and Operations	N/A	Adoption held in abeyance at this time
FAC-001-3 (errata revision)[1]	Facility Interconnection Requirements	R-44-23	September 8, 2023
FAC-001-4	Facility Interconnection Requirements	N/A	Adoption held in abeyance at this time[4]
FAC-002-3[1]	Facility Interconnection Studies	R-21-21	January 1, 2022
FAC-002-4	Facility Interconnection Studies	N/A	Adoption held in abeyance at this time[4]
FAC-003-4[1]	Transmission Vegetation Management	R-39-17	October 1, 2017

[2] Reliability standard would be superseded by EOP-003-2 if adopted in B.C. Adoption of EOP-003-2 pending reassessment.

[3] Reliability standard is superseded by EOP-011-1 as of the EOP-011-1 effective date in conjunction with PRC-010-2 Requirement 1 if adopted in B.C. Adoption of PRC-010-2 is held in abeyance at this time.

[4] On January 26, 2022, the BCUC Reasons for Decision for Order No. R-4-22, indicated that a separate proceeding would be initiated regarding Planning Coordinator issues and adjourned the Planning Coordinator Assessment Report.

Standard	Name	BCUC Order Adopting	Effective Date
FAC-003-5	Transmission Vegetation Management	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
FAC-008-5	Facility Ratings	R-34-22A1	April 1, 2023
FAC-010-3	System Operating Limits Methodology for the Planning Horizon	R-39-17	R1–R4: October 1, 2017 R1-R4: Retired October 1, 2025
FAC-011-3[1]	System Operating Limits Methodology for the Operations Horizon	R-39-17	October 1, 2017
FAC-011-4	System Operating Limits Methodology for the Operations Horizon	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
FAC-013-2	Assessment of Transfer Capability for the Near Term Transmission Planning Horizon	N/A	Adoption held in abeyance at this time[4, 5]
FAC-014-2[1]	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
FAC-014-3	Establish and Communicate System Operating Limits	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
FAC-501-WECC-2	Transmission Maintenance	R-21-19	October 1, 2019
INT-006-5	Evaluation of Interchange Transactions	R-34-22A1	October 29, 2022
INT-009-3	Implementation of Interchange	R-34-22A1	October 29, 2022
IRO-001-4	Reliability Coordination – Responsibilities	R-39-17	October 1, 2017
IRO-002-7	Reliability Coordination – Monitoring and Analysis	R-34-22A1	October 29, 2022
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-3	Qualified Path Unscheduled Flow (USF) Relief	R-19-20	January 1, 2021

[5] On October 15, 2020, FERC Order No. 873 approved the retirement of the reliability standard in the United States. The reliability standard was not recommended for adoption in B.C. per the Planning Coordinator Assessment Report filed with BCUC on May 31, 2021.

Standard	Name	BCUC Order Adopting	Effective Date
IRO-008-2[1]	Reliability Coordinator Operational Analyses and Real-time Assessments	R-39-17	October 1, 2017
IRO-008-3	Reliability Coordinator Operational Analyses and Real-time Assessments	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs	R-39-17	October 1, 2017
IRO-010-3[1]	Reliability Coordinator Data Specification and Collection	R-21-21	January 1, 2022
IRO-010-4[1]	Reliability Coordinator Data Specification and Collection	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
IRO-010-5	Reliability Coordinator Data Specification and Collection	R-19-24	April 1, 2026
IRO-014-3	Coordination Among Reliability Coordinators	R-39-17	October 1, 2017
IRO-017-1	Outage Coordination	R-39-17	October 1, 2020
IRO-018-1(i)	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities	R-33-18	April 1, 2020
MOD-010-0[6]	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0[6]	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	R-38-15 With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021

[6] Reliability standard will be superseded by Requirement 2 of MOD-032-1 by the effective date of MOD-032-1 Requirement 2, pending adoption in B.C.

Standard	Name	BCUC Order Adopting	Effective Date
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-031-3	Demand and Energy Data	R-21-21	January 1, 2022
MOD-032-1	Data for Power System Modeling and Analysis	N/A	Adoption held in abeyance at this time[4]
MOD-033-1	Steady-State and Dynamic System Model Validation	N/A	Adoption held in abeyance at this time[4]
NUC-001-4	Nuclear Plant Interface Coordination	R-21-21	October 1, 2021
PER-003-2	Operating Personnel Credentials	R-21-19	April 1, 2020
PER-005-2	Operations Personnel Training	R-38-15	R1-R4, R6: October 1, 2016 R5: October 1, 2017
PER-006-1	Specific Training for Personnel	R-21-19	October 1, 2021
PRC-002-2[1]	Disturbance Monitoring and Reporting Requirements	R-32-16A	R1, R5: April 1, 2017 R2-R4, R6-R11: staged as per BC-specific Implementation Plan R12: July 1, 2017
PRC-002-3[1]	Disturbance Monitoring and Reporting Requirements	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
PRC-002-4	Disturbance Monitoring and Reporting Requirements	R-19-24	October 1, 2025

Standard	Name	BCUC Order Adopting	Effective Date
PRC-004-6	Protection System Misoperation Identification and Correction	R-34-22A1	April 1, 2023
PRC-005-1.1b[1, 7]	Transmission and Generation Protection System Maintenance and Testing	R-32-14	January 1, 2015
PRC-005-6	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance	R-39-17	R1, R2, R5: October 1, 2019 R3, R4: See BC-specific Implementation Plan
PRC-006-5	Automatic Underfrequency Load Shedding	N/A	Adoption held in abeyance at this time[4]
PRC-007-0[8]	Assuring Consistency of Entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0[7]	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010
PRC-009-0[8]	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[5]
PRC-010-2	Under Voltage Load Shedding	N/A	Adoption held in abeyance at this time[4]
PRC-011-0[7]	Undervoltage Load Shedding System Maintenance and Testing	G-67-09	November 1, 2010

[7] Reliability standard is superseded by PRC-005-6 as per the PRC-005-6 B.C. specific Implementation Plan.

[8] Reliability standard will be superseded by PRC-006-5 if adopted in B.C.

Standard	Name	BCUC Order Adopting	Effective Date
PRC-012-2	Remedial Action Schemes	R-33-18	October 1, 2021 R1: Attachment 1, Section II Parts 6(d) and 6(e) to be determined[4] R2: Attachment 2, Section I Parts 7(d) and 7(e) to be determined[4] R4: To be determined[4]
PRC-017-1[7]	Remedial Action Scheme Maintenance and Testing	R-39-17	October 1, 2017
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	R-32-16A With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021
PRC-021-1[9]	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010
PRC-022-1[9]	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010 R2: Retired January 21, 2014[5]
PRC-023-2[1, 10]	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: Adoption held in abeyance at this time[4] R6: Adoption held in abeyance at this time[4]

[9] Reliability standard is superseded by PRC-010-2 if adopted in B.C.

[10] PRC-023-2 Requirement 1, Criterion 6 only is superseded by PRC-025-2 as of PRC-025-2's 100 per cent Effective Date.

Standard	Name	BCUC Order Adopting	Effective Date
PRC-023-4[1]	Transmission Relay Loadability	R-39-17	R1-R5 Circuits 4.2.1.1, 4.2.1.4: October 1, 2017 with the exception of Criterion 6 of R1 which will not become effective until PRC-025-2 R1 is completely effective in BC. Until then, PRC-023-2 R1, Criterion 6 will remain in effect R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: Adoption held in abeyance at this time[4]
PRC-023-5	Transmission Relay Loadability	R-44-23	R1-R5 Circuits 4.2.1.1 and 4.2.1.4: October 1, 2025 except R1 criterion 6 which will not become effective until PRC-025-2 is completely effective in BC Until then, PRC-023-2 R1 Criterion 6 remains in effect R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: Adoption held in abeyance at this time[4]
PRC-024-3	Frequency and Voltage Protection Settings for Generating Resources	R-21-21	October 1, 2023
PRC-025-2	Generator Relay Loadability	R-21-19	October 1, 2019 and staged per BC-specific Implementation Plan
PRC-026-2	Relay Performance During Stable Power Swings	N/A	Adoption held in abeyance at this time[4]
PRC-027-1	Coordination of Protection Systems for Performance During Faults	R-21-19	October 1, 2021
TOP-001-1a[11]	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013

[11] Refer to “TOP Reliability Standards Supersession Mapping” section below.

Standard	Name	BCUC Order Adopting	Effective Date
TOP-001-5[1]	Transmission Operations	R-34-22A1	October 29, 2022
TOP-001-6	Transmission Operations	R-44-23	October 1, 2025 and as per BC-specific Implementation Plan
TOP-002-4	Operations Planning	R-39-17 With revised effective dates by Order R-14-20	April 1, 2021
TOP-003-4[1]	Operational Reliability Data	R-21-21	January 1, 2022
TOP-003-5[1]	Operational Reliability Data	R-34-22A1	July 1, 2024 and as per BC-specific Implementation Plan
TOP-003-6.1	Transmission Operator and Balancing Authority Data and Information Specification and Collection	R-19-24	April 1, 2026
TOP-007-0[11]	Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	November 1, 2010
TOP-008-1[11]	Response to Transmission Limit Violations	G-67-09	November 1, 2010
TOP-010-1(i)	Real-time Reliability Monitoring and Analysis Capabilities	R-33-18 With revised effective dates by Order R-14-20	April 1, 2021
TPL-001-4[1]	Transmission System Planning Performance Requirements	R-27-18A	R1: July 1, 2019 R2-R6, R8: July 1, 2020 R7: Adoption held in abeyance at this time[4]
TPL-001-5.1	Transmission System Planning Performance Requirements	N/A	Adoption held in abeyance at this time[4]
TPL-007-4	Transmission System Planned Performance for Geomagnetic Disturbance Events	N/A	Adoption held in abeyance at this time[4]
VAR-001-5	Voltage and Reactive Control	R-21-19	October 1, 2019

Standard	Name	BCUC Order Adopting	Effective Date
VAR-002-4.1	Generator Operation for Maintaining Network Voltage Schedules	R-33-18	October 1, 2018
VAR-501-WECC-3.1	Power System Stabilizer (PSS)	R-33-18	October 1, 2020 R3: For units placed into service after the effective date: January 1, 2021 For units placed into service prior to the effective date: January 1, 2024

British Columbia Utilities Commission

TOP Reliability Standards
Supersession Mapping

This following mapping shows the supersession of Requirements for the following TOP reliability standards by the revised/replacement reliability standards indicated which are either adopted or yet to be adopted in B.C. as of the effective date in the "B.C. Reliability Standards" section above:

TOP-001-1a	—	Reliability Responsibilities and Authorities
TOP-007-0	—	Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
TOP-008-1	—	Response to Transmission Limit Violations

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirements R1, R2, R4, R5, R6	TOP-001-5
Requirement R3	IRO-001-4 TOP-001-5
Requirement R7	TOP-001-5 TOP-003-4 IRO-010-3
Requirement R8	EOP-003-2, Requirement 1 (adoption held in abeyance in B.C. due to PA/PC dependencies) IRO-009-2

Standard TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-008-2 TOP-001-5
Requirement R2	IRO-009-2 TOP-001-5
Requirement R3	EOP-003-2, Requirement 1 (adoption held in abeyance in B.C. due to PA/PC dependencies) IRO-009-2
Requirement R4	IRO-008-2

Standard TOP-008-1 — Response to Transmission Limit Violations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirements R1	EOP-003-2, Requirement 1 (adoption held in abeyance in BC due to PA/PC dependencies) TOP-001-5
Requirements R2 and R3	TOP-001-5
Requirement R4	TOP-001-5 TOP-002-4 TOP-003-4

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

Updated by Order R-19-24, dated July 16, 2024

Introduction:

This document is to be used in conjunction with the NERC Glossary dated March 8, 2023.

- The NERC Glossary terms listed in Table 1 below are effective in B.C. on the date specified in the "Effective Date" column.
- Table 2 below outlines the adoption history by the BCUC of the NERC Glossaries in B.C.
- Any NERC Glossary terms and definitions in the NERC Glossary that are not approved by FERC on or before November 30, 2023 are of no force or effect in B.C.
- Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in B.C.
- The Texas Regional Entity, 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 B.C.

Table 1: B.C. Effective Date Exceptions to Definitions in the March 8, 2023 Version of the NERC Glossary

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Actual Frequency (FA)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Actual Net Interchange (NIA)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Automatic Time Error Correction (IATEC)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Adjacent Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Alternative Interpersonal Communication	-	Report No. 9	R-32-16A	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 Generation Control	AGC	Report No. 11	R-33-18	Adoption	October 1, 2019
Automatic Time Error Correction	-	Report No. 7	R-32-14	Adoption	October 1, 2014
Balancing Authority	-	Report No. 11	R-33-18	Adoption	January 1, 2019
Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
BES Cyber Asset[2]	-	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,

[1] FERC approved terms in the NERC Glossary of Terms as of February 7, 2017; intended for BAL-002-2.

[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	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
					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 Asset	BCA	Report No. 10	R-39-17	Adoption	October 1, 2018
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.
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[2]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Blackstart Resource	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Bulk Electric System	BES	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System[2]	-	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Bus-tie Breaker	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Cascading	-	Report No. 10	R-39-17	Adoption	October 1, 2017
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.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
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-32-16A	Adoption	October 1, 2017
Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Contingency Event Recovery Period[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve Restoration Period[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contributing Schedule (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
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-32-16A	Retirement	September 30, 2018
Critical Cyber Assets	-	Report No. 9	R-32-16A	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,

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
					CIP-010-1, and CIP-011-1) where this term is referenced.
Cyber Security Incident[2]	-	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. 13	R-19-20	Adoption	April 1, 2023
Demand-Side Management	DSM	Report No. 9	R-32-16A	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.
Distribution Provider	DP	Report No. 10	R-39-17	Adoption	October 1, 2017
Disturbance	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Dynamic Interchange Schedule or Dynamic Schedule	-	Report No. 8	R-38-15	Adoption	October 1, 2015
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.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
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.
Element	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Energy Emergency[2]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Energy Emergency	-	Report No. 11	R-33-18	Retirement	October 1, 2018
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.
Extreme Cold Weather Temperature	-	Report No. 17	R-19-24	N/A	To be determined.
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
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
Generator Cold Weather Critical Component	-	Report No. 17	R-19-24	N/A	To be determined.
Generator Cold Weather Reliability Event	-	Report No. 17	R-19-24	N/A	To be determined.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Generator Operator	GOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Generator Owner	GO	Report No. 10	R-39-17	Adoption	October 1, 2017
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	GMD	Report No. 10	R-39-17	Adoption	To be determined[3]
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.
Interchange Authority	IA	Report No. 10	R-39-17	Adoption	October 1, 2017
Interchange Meter Error (IME)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Interconnected Operations Service	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection	-	Report No. 10	R-39-17	Adoption	October 1, 2017
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-32-16A	Adoption	October 1, 2017

[3] The NERC Glossary term is associated with reliability standard that is dependent on the Planning Authority/Planning Coordinator function. The BCUC Reasons for Decision for Order No. R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to BC.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Load-Serving Entity	LSE	Report No. 10	R-39-17	Adoption	October 1, 2017
Long-Term Transmission Planning Horizon	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Minimum Vegetation Clearance Distance	MVCD	Report No. 7	R-32-14	Adoption	August 1, 2015
Misoperation	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Most Severe Single Contingency[1]	MSSC	Report No. 10	R-39-17	Adoption	January 1, 2018
Native Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Non-Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Non-Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Operating Instruction	-	Report No. 9	R-32-16A	Adoption	April 1, 2017
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[2]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Operational Planning Analysis	OPA	Report No. 12	R-21-19	Adoption	October 1, 2021
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,

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
					CIP-010-1, and CIP-011-1) where this term is referenced.
Planning Assessment	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Planning Authority	PA	Report No. 10	R-39-17	Adoption	October 1, 2017
Point of Receipt	POR	Report No. 10	R-39-17	Adoption	October 1, 2017
Pre-Reporting Contingency Event ACE Value[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Protected Cyber Assets[2]	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.
Protected Cyber Assets	PCA	Report No. 10	R-39-17	Adoption	October 1, 2018
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 Coordination Study	-	Report No. 12	R-21-19	Adoption	October 1, 2021
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-005-6)	PSMP	Report No. 10	R-39-17	Adoption	October 1, 2019

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Pseudo-Tie[2]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Pseudo-Tie	-	Report No. 11	R-33-18	Adoption	January 1, 2019
Qualified Controllable Device (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Qualified Path (WECC Regional Term)	-	Report No. 13	R-19-20	Adoption	January 1, 2021
Qualified Transfer Path (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Qualified Transfer Path Curtailment Event (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Reactive Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real-time Assessment[2]	-	Report No. 6	R-41-13	Adoption	January 1, 2014
Real-time Assessment[2]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Real-time Assessment	RTA	Report No. 12	R-21-19	Adoption	October 1, 2021
Reliability Adjustment Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Reliability Coordinator	RC	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliability Directive	-	Report No. 9	R-32-16A	Retirement	July 18, 2016
Reliability Standard[2]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliability Standard	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliable Operation[2]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliable Operation	-	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
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
Relief Requirement (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Remedial Action Scheme[2]	RAS	Report No. 1	G-67-09	Adoption	June 4, 2009
Remedial Action Scheme	RAS	Report No. 9		-	To be determined3
Removable Media[2]	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Removable Media	-	Report No. 12	R-21-19	Adoption	October 1, 2019
Reporting ACE	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Reportable Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Reportable Cyber Security Incident[2]	-	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.
Reportable Cyber Security Incident	-	Report No. 13	R-19-20	Adoption	April 1, 2023
Request for Interchange	RFI	Report No. 8	R-38-15	Adoption	October 1, 2015
Reserve Sharing Group	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reserve Sharing Group Reporting ACE[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Resource Planner	RP	Report No. 10	R-39-17	Adoption	October 1, 2017
Scheduled Net Interchange (NIS)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Sink Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Source Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Special Protection System (Remedial Action Scheme)[2]	SPS	Report No. 1	G-67-09	Adoption	June 4, 2009
Special Protection System (Remedial Action Scheme)	SPS	Report No. 10	R-39-17	Adoption	Held in abeyance due to PC dependencies
Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
System Operating Limit[2]	SOL	Report No. 10	R-39-17	Adoption	October 1, 2017
System Operating Limit	-	Report No. 16	R-44-23	Adoption	October 1, 2025
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.
System Voltage Limit	-	Report No. 16	R-44-23	Adoption	October 1, 2025
Total Internal Demand	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Transient Cyber Asset[2]	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Transient Cyber Asset	TCA	Report No. 12	R-21-19	Adoption	October 1, 2019
Transmission Customer	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Transfer Distribution Factor (WECC Regional Term)	TDF	Report No. 13	R-19-20	Retirement	December 31, 2020
Transmission Operator	TOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Owner	TO	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Planner	TP	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Transmission Service Provider	TSP	Report No. 10	R-39-17	Adoption	October 1, 2017
Under Voltage Load Shedding Program	-	Report No. 9		-	To be determined[3]
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

Table 2: NERC Glossary Adoption History in BC

<table>
<tr><th>NERC Glossary of Terms Version Date</th><th>Assessment Report Number</th><th>BCUC Order Adoption Date</th><th>BCUC Order Adopting</th><th>Effective Date</th></tr>
<tr><td>February 12, 2008</td><td>Report No. 1</td><td>June 4, 2009</td><td>G-67-09</td><td rowspan="19">1. The NERC Glossaries listed became effective as of the date of the respective BCUC Orders adopting them. See the exception of the BAL-001-2 Glossary Terms within the NERC Glossary dated December 7, 2015.[1]
2. Specific effective dates of new and revised NERC Glossary terms adopted in a BCUC Order appear in attachments 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.
3. NERC Glossary terms which have not been approved by FERC are of no force or effect in B.C.
4. Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in B.C.
5. 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 B.C.</td></tr>
<tr><td>April 20, 2010</td><td>Report No. 2</td><td>November 10, 2010</td><td>G-167-10</td></tr>
<tr><td>August 4, 2011</td><td>Report No. 3</td><td>September 1, 2011</td><td>G-162-11 replacing G-151-11</td></tr>
<tr><td>December 13, 2011</td><td>Report No. 5</td><td>January 15, 2013</td><td>R-1-13</td></tr>
<tr><td>December 5, 2012</td><td>Report No. 6</td><td>December 12, 2013</td><td>R-41-13</td></tr>
<tr><td>January 2, 2014</td><td>Report No. 7</td><td>July 17, 2014</td><td>R-32-14</td></tr>
<tr><td>October 1, 2014</td><td>Report No. 8</td><td>July 24, 2015</td><td>R-38-15</td></tr>
<tr><td>December 7, 2015</td><td>BAL-001-2</td><td>April 21, 2016</td><td>R-14-16</td></tr>
<tr><td>December 7, 2015</td><td>Report No. 9[2]</td><td>July 18, 2016</td><td>R-32-16A</td></tr>
<tr><td>November 28, 2016</td><td>Report No. 10</td><td>July 26, 2017</td><td>R-39-17</td></tr>
<tr><td>November 28, 2016</td><td>TPL-001-4</td><td>June 28, 2018</td><td>R-27-18A</td></tr>
<tr><td>October 6, 2017</td><td>Report No. 11</td><td>October 1, 2018</td><td>R-33-18</td></tr>
<tr><td>July 3, 2018</td><td>Report No.12</td><td>September 26, 2019</td><td>R-21-19</td></tr>
<tr><td>August 12, 2019</td><td>Report No. 13</td><td>September 8, 2020</td><td>R-19-20</td></tr>
<tr><td>October 8, 2020</td><td>Report No. 14</td><td>September 21, 2021</td><td>R-21-21</td></tr>
<tr><td>June 28, 2021</td><td>Report No. 15</td><td>October 28, 2022</td><td>R-34-22A1</td></tr>
<tr><td>March 29, 2022</td><td>Report No. 16</td><td>September 8, 2023</td><td>R-44-23</td></tr>
<tr><td>March 8, 2023</td><td>Report No. 17</td><td>July 16, 2024</td><td>R-19-24</td></tr>
</table>

British Columbia Utilities Commission

Implementation Plan for CIP-003-9

Applicable Standard(s)

- CIP-003-9 — Cyber Security — Security Management Controls

Requested Retirement(s)

- CIP-003-8 — Cyber Security — Security Management Controls

Prerequisite Standard(s) or Definitions

- These standard(s) or definitions must be approved before the Applicable Standard becomes effective:
- None

Applicable Entities

- Balancing Authority
- Distribution Provider[1]
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

General Considerations

The intent of the Initial Performance of Periodic Requirements section is for Responsible Entities to remain on the same time interval of the prior versions of the standards for their performance of the requirements under the new versions.

Effective Date and Phased-In Compliance Dates

The effective date for the proposed Reliability Standard is provided below.

Reliability Standard CIP-003-9

Reliability Standard CIP-003-9 shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the BCUC order adopting the Reliability Standard.

Initial Performance of Periodic Requirements

Periodic requirements contain time parameters for subsequent and recurring iterations of the requirement,

[1] See Applicability section of CIP-003-9 for additional information on Distribution Providers subject to the standard.

such as, but not limited to, "...at least once every 15 calendar months...", and Responsible Entities shall comply initially with those periodic requirements in CIP-003-9 as follows:

Responsible Entities shall initially comply with Requirement R1, Part 1.2.6 on or before the effective date of CIP-003-9.

Responsible Entities shall initially comply with all other periodic requirements in CIP-003-9 within the periodic timeframes of their last performance under CIP-003-8.

Planned or Unplanned Changes

The following is replicated from the BCUC Implementation Plan for CIP-003-8 under Order No. R-19-20 with references to CIP-003-8 adjusted to CIP-003-9.

Planned or Unplanned Changes Resulting in a Higher Categorization

Planned changes refer to any changes of the electric system or BES Cyber System as identified through the annual assessment under CIP-002-5 (or any subsequent version of that Reliability Standard) which were planned and implemented by the responsible entity.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-5, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change.

In contrast, unplanned changes refer to any changes of the electric system or BES Cyber System, as identified through the annual assessment under CIP-002-5, Requirement R2, which were not planned by the responsible entity. Consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-5, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-5, Attachment 1, criteria.

For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in CIP-003-9 on the update of the identification and categorization of the affected BES Cyber System.

For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in CIP-003-9 according to the following timelines, following the identification and categorization of the affected BES Cyber System.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 Months
New medium impact BES Cyber System	12 Months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium-Impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 Months
Responsible entity identifies first medium impact or High impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP 002-5 identification and categorization processes)	24 Months

Unplanned Changes Resulting in Low Impact Categorization

For unplanned changes resulting in a Low Impact BES Cyber System categorization where previously the asset containing Cyber Assets had no categorization, the Responsible Entity shall comply with all Requirements applicable to Low Impact BES Cyber Systems within 12 calendar months following the identification and categorization of the affected BES Cyber System.

Retirement Date

Reliability Standard CIP-003-8

Reliability Standard CIP-003-8 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-9 in British Columbia.

A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-9
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).
4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency Load shedding (UFLS) orundervoltage Load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subjectto one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in Section 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-003-9:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates*: See BC Implementation Plan for CIP-003-9.

B. Requirements and Measures

R1. Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. For its high impact and medium impact BES Cyber Systems, if any:

1.1.1. Personnel and training (CIP-004);

1.1.2. Electronic Security Perimeters (CIP-005) including Interactive Remote Access;

1.1.3. Physical security of BES Cyber Systems (CIP-006);

1.1.4. System security management (CIP-007);

1.1.5. Incident reporting and response planning (CIP-008);

1.1.6. Recovery plans for BES Cyber Systems (CIP-009);

1.1.7. Configuration change management and vulnerability assessments (CIP-010);

1.1.8. Information protection (CIP-011); and

1.1.9. Declaring and responding to CIP Exceptional Circumstances.

1.2. For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:

1.2.1. Cyber security awareness;

1.2.2. Physical security controls;

1.2.3. Electronic access controls;

1.2.4. Cyber Security Incident response;

1.2.5. Transient Cyber Assets and Removable Media malicious code risk mitigation;

1.2.6. Vendor electronic remote access security controls; and

1.2.7. Declaring and responding to CIP Exceptional Circumstances.

M1. Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

R2. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cybersecurity plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Note: An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. Lists of authorized users are not required.

M2. Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.

R3. Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

R4. The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

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 Responsible Entity 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:

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar 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.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			BES Cyber Systems, but did not address one of the seven topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented	BES Cyber Systems, but did not address two of the seven topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented	BES Cyber Systems, but did not address three of the seven topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented	four or more of the seven topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.2)	cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.2)	cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	the previous approval. (R1.2)
R2	**Operations Planning**	**Lower**	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2,	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2)	The Responsible Entity failed to document and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			The Responsible Entity implemented electronic access controls but failed to document its cyber security plan(s) for electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plan(s) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or	Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2)	OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets containing low impact BES Cyber Systems, but failed to permit only necessary inbound and outbound electronic access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to Requirement R2, Attachment 1, Section 5.1. (R2) OR	OR The Responsible Entity documented its cyber security plan(s) for electronic access controls but failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for	Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			The Responsible Entity documented its plan(s) for Transient Cyber Assets, but failed to document the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2) OR The Responsible Entity implemented vendor electronic remote access security controls but failed to document its cyber security process for vendor electronic remote access security controls according to Requirement R2, Attachment 1, Section 6. (R2)	identification, classification, and response to Cyber Security Incidents according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to	plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Sections 5.1 and 5.3. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document	according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System according to Requirement R2, Attachment 1, Section 5.3. (R2) OR The Responsible Entity failed to document and implement its cyber security process for vendor electronic	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2) OR The Responsible Entity documented its cyber security process for vendor electronic	remote access security controls according to Requirement R2, Attachment 1, Section 6. (R2)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				remote access security controls, but failed to implement vendor electronic remote access security controls according to Requirement R2, Attachment 1, Section 6. (R2)		
R3	**Operations Planning**	**Medium**	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	**Operations Planning**	**Lower**	The Responsible Entity has identified a delegate by name, title, date of delegation, and	The Responsible Entity has identified a delegate by name, title, date of delegation, and	The Responsible Entity has identified a delegate by name, title, date of delegation, and	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-9)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5.	
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from

Version	Date	Action	Change Tracking
			Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7	2/9/17	Adopted by the NERC Board of Trustees.	Revised to address FERC Order No. 822 directives regarding (1) the definition of LERC and (2) transient devices.
7	4/19/18	FERC Order issued approving CIP-003-7. Docket No. RM17-11-000	
8	5/9/19	Adopted by the NERC Board of Trustees.	Removed SPS references. Revised to address FERC Order No. 843 regarding mitigating the risk of malicious code.
8	7/31/2019	FERC Order issued approving CIP-003-8. Docket No. RD19-5-000.	

Version	Date	Action	Change Tracking
9	11/16/2022	Adopted by the NERC Board of Trustees.	Revisions to address NERC Board Resolution and the Supply Chain Report
9	3/16/2023	FERC Order issued approving CIP-003-9. Docket No. RD23-3-000.	
9	3/22/2023	Effective Date	April 1, 2026

Attachment 1

Required Sections for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Responsible Entities shall include each of the sections provided below in the cyber security plan(s) required under Requirement R2.

Responsible Entities with multiple-impact BES Cyber Systems ratings can utilize policies, procedures, and processes for their high or medium impact BES Cyber Systems to fulfill the sections for the development of low impact cyber security plan(s). Each Responsible Entity can develop a cyber security plan(s) either by individual asset or groups of assets.

Section 1. Cyber Security Awareness: Each Responsible Entity shall reinforce, at least once every 15 calendar months, cyber security practices (which may include associated physical security practices).

Section 2. Physical Security Controls: Each Responsible Entity shall control physical access, based on need as determined by the Responsible Entity, to (1) the asset or the locations of the low impact BES Cyber Systems within the asset, and (2) the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.

Section 3. Electronic Access Controls: For each asset containing low impact BES Cyber System(s) identified pursuant to CIP-002, the Responsible Entity shall implement electronic access controls to:

3.1 Permit only necessary inbound and outbound electronic access as determined by the Responsible Entity for any communications that are:

i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);

ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and

iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).

3.2 Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

Section 4. Cyber Security Incident Response: Each Responsible Entity shall have one or more Cyber Security Incident response plan(s), either by asset or group of assets, which shall include:

4.1 Identification, classification, and response to Cyber Security Incidents;

4.2 Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;

4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;

4.4 Incident handling for Cyber Security Incidents;

4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and

4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation: Each Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more plan(s) to achieve the objective of mitigating the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media. The plan(s) shall include:

5.1 For Transient Cyber Asset(s) managed by the Responsible Entity, if any, the use of one or a combination of the following in an ongoing or on-demand manner (per Transient Cyber Asset capability):

- Antivirus software, including manual or managed updates of signatures or patterns;
- Application whitelisting; or
- Other method(s) to mitigate the introduction of malicious code.

5.2 For Transient Cyber Asset(s) managed by a party other than the Responsible Entity, if any:

5.2.1 Use one or a combination of the following prior to connecting the Transient Cyber Asset to a low impact BES Cyber System (per Transient Cyber Asset capability):

- Review of antivirus update level;
- Review of antivirus update process used by the party;
- Review of application whitelisting used by the party;
- Review use of live operating system and software executable only from read-only media;

- Review of system hardening used by the party; or
- Other method(s) to mitigate the introduction of malicious code.

5.2.2 For any method used pursuant to 5.2.1, Responsible Entities shall determine whether any additional mitigation actions are necessary and implement such actions prior to connecting the Transient Cyber Asset.

5.3 For Removable Media, the use of each of the following:

5.3.1 Method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System; and

5.3.2 Mitigation of the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System.

Section 6. Vendor Electronic Remote Access Security Controls: For assets containing low impact BES Cyber System(s) identified pursuant to CIP-002, that allow vendor electronic remote access, the Responsible Entity shall implement a process to mitigate risks associated with vendor electronic remote access, where such access has been established under Section 3.1. These processes shall include:

6.1 One or more method(s) for determining vendor electronic remote access;

6.2 One or more method(s) for disabling vendor electronic remote access; and

6.3 One or more method(s) for detecting known or suspected inbound and outbound malicious communications for vendor electronic remote access.

Attachment 2

Examples of Evidence for Cyber Security Plan(s) for Assets Containing Low Impact BES Cyber Systems

Section 1. Cyber Security Awareness: An example of evidence for Section 1 may include, but is not limited to, documentation that the reinforcement of cyber security practices occurred at least once every 15 calendar months. The evidence could be documentation through one or more of the following methods:

- Direct communications (for example, e-mails, memos, or computer-based training);
- Indirect communications (for example, posters, intranet, or brochures); or
- Management support and reinforcement (for example, presentations or meetings).

Section 2. Physical Security Controls: Examples of evidence for Section 2 may include, but are not limited to:

- Documentation of the selected access control(s) (e.g., card key, locks, perimeter controls), monitoring controls (e.g., alarm systems, human observation), or other operational, procedural, or technical physical security controls that control physical access to both:
  a. The asset, if any, or the locations of the low impact BES Cyber Systems within the asset; and
  b. The Cyber Asset(s) specified by the Responsible Entity that provide(s) electronic access controls implemented for Attachment 1, Section 3.1, if any.

Section 3. Electronic Access Controls: Examples of evidence for Section 3 may include, but are not limited to:

1. Documentation showing that at each asset or group of assets containing low impact BES Cyber Systems, routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset is restricted by electronic access controls to permit only inbound and outbound electronic access that the Responsible Entity deems necessary, except where an entity provides rationale that communication is used for time-sensitive protection or control functions between intelligent electronic devices. Examples of such documentation may include, but are not limited to representative diagrams that illustrate control of inbound and outbound communication(s) between the low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) or lists of implemented electronic access controls (e.g., access control lists restricting IP addresses, ports, or services; implementing unidirectional gateways).

2. Documentation of authentication for Dial-up Connectivity (e.g., dial out only to a preprogrammed number to deliver data, dial-back modems, modems that must be remotely controlled by the control center or control room, or access control on the BES Cyber System).

Section 4. Cyber Security Incident Response: An example of evidence for Section 4 may include, but is not limited to, dated documentation, such as policies, procedures, or process documents of one or more Cyber Security Incident response plan(s) developed either by asset or group of assets that include the following processes:

1. to identify, classify, and respond to Cyber Security Incidents; to determine whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and for notifying the Electricity Information Sharing and Analysis Center (E-ISAC);
2. to identify and document the roles and responsibilities for Cyber Security Incident response by groups or individuals (e.g., initiating, documenting, monitoring, reporting, etc.);
3. for incident handling of a Cyber Security Incident (e.g., containment, eradication, or recovery/incident resolution);
4. for testing the plan(s) along with the dated documentation that a test has been completed at least once every 36 calendar months; and
5. to update, as needed, Cyber Security Incident response plan(s) within 180 calendar days after completion of a test or actual Reportable Cyber Security Incident.

Section 5. Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation:

1. Examples of evidence for Section 5.1 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.
2. Examples of evidence for Section 5.2.1 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that

identifies the Responsible Entity's acceptance that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate malicious code for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Examples of evidence for Attachment 1, Section 5.2.2 may include, but are not limited to, documentation from change management systems, electronic mail, or contracts that identifies a review to determine whether additional mitigation is necessary and has been implemented prior to connecting the Transient Cyber Asset managed by a party other than the Responsible Entity.

3. Examples of evidence for Section 5.3.1 may include, but are not limited to, documented process(es) of the method(s) used to detect malicious code such as results of scan settings for Removable Media, or implementation of on-demand scanning. Examples of evidence for Section 5.3.2 may include, but are not limited to, documented process(es) for the method(s) used for mitigating the threat of detected malicious code on Removable Media, such as logs from the method(s) used to detect malicious code that show the results of scanning and the mitigation of detected malicious code on Removable Media or documented confirmation by the entity that the Removable Media was deemed to be free of malicious code.

Section 6. Vendor Electronic Remote Access Security Controls**:** Examples of evidence showing the implementation of the process for Section 6 may include, but are not limited to:

1. For Section 6.1, documentation showing:
    - steps to preauthorize access;
    - alerts generated by vendor log on;
    - session monitoring;
    - security information management logging alerts;
    - time-of-need session initiation;
    - session recording;
    - system logs; or
    - other operational, procedural, or technical controls.
2. For Section 6.2, documentation showing:
    - disabling vendor electronic remote access user or system accounts;

- disabling inbound and/or outbound hardware or software ports, services, or access permissions on applications, firewall, IDS/IPS, router, switch, VPN, Remote Desktop, remote control, or other hardware or software used for providing vendor electronic remote access;
- disabling communications protocols (such as IP) used for systems which establish and/or maintain vendor electronic remote access;
- Removing physical layer connectivity (e.g., disconnect an Ethernet cable, power down equipment);
- administrative control documentation listing the methods, steps, or systems used to disable vendor electronic remote access; or
- other operational, procedural, or technical controls.

3. For Section 6.3, documentation showing implementation of processes or technologies which have the ability to detect malicious communications such as:
    - Anti-malware technologies;
    - Intrusion Detection System (IDS)/Intrusion Prevention System (IPS);
    - Automated or manual log reviews;
    - alerting; or
    - other operational, procedural, or technical controls.

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-3**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator
5. **Effective Date*:**

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shedding during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for underfrequency load shed (UFLS) or undervoltage load

* Mandatory BC Effective Date: To be determined

shed (UVLS); and

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. cold weather conditions; and

1.2.6.2. extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for Transmission Operators to implement operator-controlled manual Load shed in accordance with Requirement R1 Part 1.2.5; and

2.2.9. Provisions to determine reliability impacts of:

2.2.9.1. cold weather conditions; and

2.2.9.2. extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission.

1.2. Evidence Retention

The following evidence retention period(s) 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 applicable entity 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 Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4 and Measures M1 and M4.

- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	Real-time Operations, Operations	High	N/A	The Balancing Authority developed a Reliability Coordinator-	The Balancing Authority developed an Operating Plan(s) to mitigate operating	The Balancing Authority failed to develop an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Planning, Long-term Planning			reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operator within 30 calendar days.	
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
2	August 24,2021	Effective Date	4/1/ 2023
2	October 28,2022	FERC Approved EOP-011-3 Docket Number RD23-1-000	
3	February 16,2022	Adopted by Board of Trustees	Revised under Project 2021-07
3	TBD	Effective Date	

Attachment 1-EOP-011-3
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**
   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**
   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Wheneverenergy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

A. Introduction

1. **Title:** **Extreme Cold Weather Preparedness and Operations**

2. **Number:** EOP-012-1

3. **Purpose:** To address the effects of operating in extreme cold weather by ensuring each Generator Owner has developed and implemented plan(s) to mitigate the reliability impacts of extreme cold weather on its generating units.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner

   4.1.2. Generator Operator

   4.2. Facilities:

   4.2.1 For purposes of this standard, the term "generating unit" subject to these requirements refers to the following Bulk Electric System (BES) resources:

   4.2.1.1 A Bulk Electric System generating unit that commits or is obligated to serve a Balancing Authority load pursuant to a tariff obligation, state requirement as defined by the relevant electric regulatory authority, or other contractual arrangement, rule, or regulation, for a continuous run of four hours or more at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius); or

   4.2.1.2 A Blackstart Resource

   4.2.2 Exemptions:

   4.2.2.1 Any Bulk Electric System generating unit included under Section 4.2.1 above that has a calculated Extreme Cold Weather Temperature exceeding 32 degrees Fahrenheit (zero degrees Celsius) under Requirement R3 Part 3.1 and as part of the required five year review in Requirement R4 Part 4.1 is exempt from further requirements in this standard.

   4.2.2.2 A Bulk Electric System generating unit that is not committed or obligated to operate at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius) for any continuous run of more than four hours, but is called upon to operate for more than four hours in order to assist in the mitigation of BES Emergencies, Capacity Emergencies, or Energy Emergencies during periods at or below a temperature of 32 degrees Fahrenheit (zero degrees Celsius).

5. **Effective Date*:**

* Mandatory BC Effective Date: To be determined

B. Requirements and Measures

R1. For each generating unit(s) with a commercial operation date subsequent to [Effective Date of this requirement], the Generator Owner shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

- Implement freeze protection measures that provide capability to operate for a period of not less than twelve (12) continuous hours at the Extreme Cold Weather Temperature for the unit(s), assuming a concurrent twenty (20) mph wind speed on any exposed Generator Cold Weather Critical Components; or
- Explain in a declaration any technical, commercial, or operational constraints, as defined by the Generator Owner, that preclude the ability to implement appropriate freeze protection measures to provide capability of operating for twelve (12) hours at the documented Extreme Cold Weather Temperature.

M1. Each Generator Owner will have dated evidence that demonstrates it has the capability to operate in accordance with Requirement R1. Acceptable evidence may include, but is not limited to, the following (electronic or hardcopy format): Documentation of cold weather preparedness plan, documentation of design features, any declaration that contains dated documentation to support constraints identified by the Generator Owner.

R2. For each generating unit(s) in commercial operation prior to [Effective Date of this requirement], the Generator Owner shall ensure its generating unit(s) add new or modify existing freeze protection measures as needed to provide the capability to operate for a period of not less than one (1) hour at the unit(s) Extreme Cold Weather Temperature. Generating unit(s) that are not capable of operating for one (1) hour at its Extreme Cold Weather Temperature shall develop a Corrective Action Plan (CAP) for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning, Operations Planning*]

M2. Each Generator Owner will have dated evidence that demonstrates it has freeze protection measures for its unit(s) in accordance with R2, or it has developed a CAP for the identified issues. Acceptable evidence may include the following (electronic or hardcopy format): Identification of generating units minimum temperature per Part 3.5.2 which is equal to or less than the unit's Extreme Cold Weather Temperature, documentation of freeze protection measures, cold weather preparedness plan, and CAP(s).

R3. Each Generator Owner shall implement and maintain one or more cold weather preparedness plan(s) for its generating units. The cold weather preparedness plan(s) shall include the following, at a minimum: *[Violation Risk Factor: High] [Time Horizon: Operations Planning and Real-time Operations]*

3.1 The Extreme Cold Weather Temperature for their unit(s) including the calculation date and source of temperature data;

3.2 Documentation identifying the Generator Cold Weather Critical Components;

3.3 Documentation of freeze protection measures implemented on Generator Cold Weather Critical Components which may include measures used to reduce the cooling effects of wind determined necessary by the Generator Owner to protect against heat loss, and where applicable, the effects of freezing precipitation (e.g., sleet, snow, ice, and freezing rain);

3.4 Annual inspection and maintenance of generating unit(s) freeze protection measures; and

3.5 Generating unit(s) cold weather data, to include:

3.5.1 Generating unit(s) operating limitations in cold weather to include:

3.5.1.1 Capability and availability;

3.5.1.2 Fuel supply and inventory concerns;

3.5.1.3 Fuel switching capabilities; and

3.5.1.4 Environmental constraints.

3.5.2 Generating unit(s) minimum:

- Design temperature;
- Historical operating temperature; or
- Current cold weather performance temperature determined by an engineeringanalysis.

M3. Each Generator Owner will have evidence documenting that its cold weather preparedness plan(s) was implemented and maintained in accordance with Requirement R3.

R4. Once every five calendar years, each Generator Owner shall for each generating unit: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Real-Time Operations]*

4.1 Calculate the Extreme Cold Weather Temperature, and update the cold weather preparedness plan if this temperature is now lower than the previous lowest calculation;

4.2 Review its documented generating unit(s) minimum temperature contained within its cold weather preparedness plan(s), pursuant to Part 3.5.2; and

4.3 Review whether its generating units have the freeze protection measures required to operate at the Extreme Cold Weather Temperature pursuant to R1 or R2 as applicable, and if not develop a CAP for the identified issues, including identification of any needed modifications to the cold weather preparedness plan required under Requirement R3.

M4. Each Generator Owner will have dated, documented evidence that it reviewed temperature data and updated its cold weatherpreparedness plan(s) in accordance with Requirement R4.

R5. Each Generator Owner in conjunction with its Generator Operator shall identify the entity responsible for providing the generating unit-specific training, and that identified entity shall provide annual training to its maintenance or operations personnel responsible for implementing the cold weather preparedness plan(s) developed pursuant to Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning]*

M5. Each Generator Operator or Generator Owner will have documented evidence that the applicable personnel completed annual training of the Generator Owner's cold weather preparedness plan(s). This evidence may include, but is not limited to, documents such as personnel training records, training materials, date of training, agendas or learning objectives, attendance at pre-work briefings, review of work order tasks, tailboards, attendance logs for classroom training, and completion records for computer-based training in fulfillment of Requirement R5.

R6. Each Generator Owner that owns a generating unit that experiences a Generator Cold Weather Reliability Event shall develop a CAP, within 150 days or by July 1, whichever is earlier, that contains at a minimum: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

6.1 A summary of the identified cause(s) for the Generator Cold Weather Reliability Event, where applicable, and any relevant associated data;

6.2 A review of applicability to similar equipment at other generating units owned by the Generator Owner;

6.3 An identification of any temporary operating limitations or impacts to the cold weather preparedness plan, that would apply until execution of the corrective action(s) identified in the CAP.

M6. Each Generator Owner will have documented evidence that it developed a CAP in accordance with Requirement R6. Acceptable evidence may include, but is not limited to, the following dated documentation (electronic or hardcopy format): CAP(s) and updated cold weather preparedness plan(s) where indicated as needed by the CAP.

R7. Each Generator Owner shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

7.1 Implement each CAP developed pursuant to Requirements R2, R4, or R6, or explain in a declaration why corrective actions are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

7.2 Update each CAP if actions or timetables change, until completed.

M7. Each Generator Owner shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables, or has explained in a declaration why corrective actions are not being implemented in accordance with Requirement R7. Acceptable evidence 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. Any declaration shall contain dated documentation to support constraints identified by 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 period(s) 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 applicable entity 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 Generator Owner shall keep data or evidence to show compliance for three years for Requirement R1, R3, and R5 and Measure M1, M3, and M5.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R2 is complete, whichever timeframe is greater, for Requirement R2 and Measure M2.
- The Generator Owner shall retain the current cold weather preparedness plan(s), as evidence of review or revision history, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R4 and Measure M4. The Generator Owner shall retain any Corrective Action Plans under Requirement R4 Part 4.3 for three years or until the Corrective Action Plan is complete, whichever timeframe is greater.

- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan under Requirement R6 is complete, whichever timeframe is greater, for Requirement R6 and Measure M6.
- The Generator Owner shall keep data or evidence to show compliance for three years, or until any Corrective Action Plan is complete, whichever time frame is greater, for Requirement R7 and Measure M7.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for 5% or less of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for 5% or less of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 5%, but less than or equal to 10% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 10%, but less than or equal to 20% of its units.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R1 for more than 20% of its units. OR The Generator Owner did not explain in a declaration any technical, commercial, or operational constraints that preclude the ability to implement appropriate freeze protection measures for more than 20% of its units.
R2.	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for 5% or less of its units. OR The Generator Owner did not develop a CAP as required by	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 5%, but less than or equal to 10% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 10%, but less than or equal to 20% of its units. OR The Generator Owner did not develop a CAP as required by Requirement R2 for more than	The Generator Owner did not have freeze protection measure(s) meeting the criteria in Requirement R2 for more than 20% of its units. OR The Generator Owner did not develop a CAP as required by

	Requirement R2 for 5% or less of its units.	5%, but less than or equal to 10% of its units.	10%, but less than or equal to 20% of its units.	Requirement R2 for more than 20% of its units.
R3.	The Generator Owner implemented a cold weather preparedness plan(s), but failed to maintain it.	The Generator Owner's cold weather preparedness plan failed to include one of the applicable Parts within Requirement R3.	The Generator Owner had and maintained a cold weather preparedness plan(s), but failed to implement it. OR The Generator Owner's cold weather preparedness plan failed to include two of the applicable requirement parts within Requirement R3.	The Generator Owner does not have cold weather preparedness plan(s). OR The Generator Owner'scold weather preparedness plan failed to include three or more of the applicable requirement parts within Requirement R3.
R4.	The Generator Owner completed the actions required in Requirement R4, but was late by 30 calendar days or less.	The Generator Owner completed the actions required in Requirement R4, but was late by greater than 30 calendar days, but less than or equal to 60 calendar days.	The Generator Owner failed to complete one of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3; OR The Generator Owner completed the actions required in Requirement R4, but was late by greater than 60 calendar days.	The Generator Owner failed to complete two or more of the applicable requirement parts in Requirement R4 Parts 4.1 through 4.3.
R5.	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:	The Generator Owner or Generator Operator failed to provide annual generating unit-specific training as described in Requirement R5 to the greater of:

	• one applicable personnel at a single generating unit; or • 5% or less of its total applicable personnel.	• two applicable personnel at a single generating unit; or • more than 5%, but less than or equal to 10% of its total applicable personnel.	• three applicable personnel at a single generating unit; or • more than 10%, but less than or equal to 15% of its total applicable personnel.	• four applicable personnel at a single generating unit; or • more than 15% of its total applicable personnel.
R6.	The Generator Owner developed a CAP, but not within 150 days or by July 1 as required in Requirement R6.	The Generator Owner's CAP failed to comply with one of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with two of the elements in Requirement R6, Parts 6.1 through 6.3.	The Generator Owner's CAP failed to comply with three of the elements in Requirement R6, Parts 6.1 through 6.3. OR The Generator Owner did not develop a CAP as required by Requirement R6.
R7.	The Generator Owner implemented a CAP or explained in a declaration why corrective actions are not being implemented, but failed to update the CAP when actions or timetables changed, in accordance with Requirement R7.			The Generator Owner failed to implement a CAP or explain in a declaration why corrective actions are not being implemented in accordance with Requirement R7.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	TBD	Drafted by Project 2021-07	New
1	October 28,2022	FERC Approved Order Number RD23-1-000 for EOP-012-1	
1	February 16,2022	Board Adopted	
1	March 1,2023	October 1, 2024	Effective Date

A. Introduction

1. **Title:** Reliability Coordinator Data and information Specification and Collection
2. **Number:** IRO-010-5
3. **Purpose:** To prevent instability, uncontrolled separation, or Cascading outages that adversely impact reliability, by ensuring each Reliability Coordinator has the data and information it needs to plan, monitor and assess the operation of its Reliability Coordinator Area.
4. **Applicability:**
   - **4.1.** Reliability Coordinator
   - **4.2.** Balancing Authority
   - **4.3.** Generator Owner
   - **4.4.** Generator Operator
   - **4.5.** Transmission Operator
   - **4.6.** Transmission Owner
   - **4.7.** Distribution Provider
5. **Effective Date*:**

* Mandatory BC Effective Date: April 1, 2026

B. Requirements

R1. The Reliability Coordinator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include but not be limited to: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

1.1. A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Reliability Coordinator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1 Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide data and information that includes, but is not limited to.

1.5.1 Specific deadlines or periodicity in which data and information is to be provided;

1.5.2 Performance criteria for the availability and accuracy of data and information, as applicable;

1.5.3 Provisions to update or correct data and information, as applicable or necessary.

1.5.4 A mutually agreeable format.

1.5.5 A mutually agreeable method(s) for securely transferring data and information.

M1. The Reliability Coordinator shall make available its dated, current, in force documented specification(s) for data and information.

R2. The Reliability Coordinator shall distribute its data and information specification(s) to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

M2. The Reliability Coordinator shall make available evidence that it has distributed its specification(s) to entities that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R3. Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall satisfy the obligations of the documented specifications . *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations)*

M3. The Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Reliability Coordinator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R2 shall make available evidence that it satisfied the obligations of the documented specification using the specified criteria. Such evidence could include but is not limited to electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

The British Columbia Utilities Commission.

1.2. Evidence Retention: The following evidence retention period(s) 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 Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider shall each 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 Reliability Coordinator shall retain its dated, current, in force documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R1, Measure M1 as well as any documents in force since the last compliance audit.

The Reliability Coordinator shall keep evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Reliability Coordinator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments for Requirement R2, Measure M2.

Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R3 and Measurement M3.

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R1	Operations Planning	Low	The Reliability Coordinator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Reliability Coordinator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Reliability Coordinator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
For the Requirement R2 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower	Moderate	High	Severe
R2	Operations Planning	Low	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, and Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Reliability Coordinator did not distribute its specification(s) as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is greater, that have data and information required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R3	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet one of the parts in Requirement Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet two of the parts in Requirement R1Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 satisfied the obligations of the documented specifications but failed to meet any of the parts in Requirement R1 Part 1.5.	The responsible entity receiving a specification(s) in Requirement R2 did not satisfy the obligations of the documented specifications .

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by Board of Trustees	New
1a	August 5, 2009	Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees	Addition
1a	March 17, 2011	Order issued by FERC approving IRO- 010-1a (approval effective 5/23/11)	
1a	November 19, 2013	Updated VRFs based on June 24, 2013 approval	
2	April 2014	Revisions pursuant to Project 2014-03	
2	November 13, 2014	Adopted by NERC Board of Trustees	Revisions under Project 2014-03
2	November 19, 2015	FERC approved IRO-010-2. Docket No. RM15-16-000	
3	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
3	October 30, 2020	FERC approved IRO-010-3. Docket No. RD20-4-000	
4	March 22, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06 Cold Weather
4	June 11, 2021	Adopted by NERC Board of Trustees	Revisions under Project 2019-06
4	August 24,2021	FERC approved IRO-010-4. Docket No. RD21-5-000	
4	August 27, 2021	Effective Date	April 1, 2023
5	August 17, 2023	Adopted by NERC Board of Trustees	Revision under project 2021-06

5	November 2, 2023	FERC Approved IRO-010-5. Docket No. RD23-6-000	
5	November 3, 2023	Effective Date	July 1, 2025

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-4
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Transmission Owner
     - **4.1.3.** Generator Owner
5. **Effective Date*:**

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-002-4, Attachment 1.

1.2. Notify the other owners of BES Elements directly connected[1] to those BES buses, that SER or FR data is required for those BES Elements, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners in accordance with Part 1.2.

M1. The Transmission Owner for Requirement R1, Part 1.1 has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-4, Attachment 1; has dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1, Part 1.2; and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1, Part 1.3.

R2. Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns directly connected 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]*

[1] For the purposes of this standard, "directly connected" BES Elements are BES Elements connected at the same voltage level within the same physical location sharing a common ground grid with the BES bus identified under Attachment 1. Transformers that have a low-side operating voltage of less than 100 kV are excluded.

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 directly 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 100 kV 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 Reliability Coordinator 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 Reliability Coordinator'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.

5.4. Re-evaluate all BES Elements within its Reliability Coordinator Area 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.

M5. The Reliability Coordinator 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 Reliability Coordinator 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 the Reliability Standard PRC-002-2[2] and is not capable of continuous recording, triggered records

[2] The effective date of the Reliability Standard PRC-002-2 in the U.S. was July 1, 2016. The effective date may be different for other jurisdictions.

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

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	>0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	>0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	>0.125 Hz/sec
○ 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 Reliability Coordinator, 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 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.

R13. Each Transmission Owner and Generator Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

13.1. Within three (3) calendar years of completing a re-evaluation or receiving notification under Requirement R1, Part 1.3, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses.

13.2. Within three (3) calendar years of receiving notification under Requirement R5, Part 5.4, have DDR data for BES Elements identified during the re-evaluation.

M13. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R13. Evidence may include, but is not limited to: letters, emails, drawings, or settings files.

C. 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 Transmission Owner, Generator Owner, 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 Reliability Coordinator shall retain evidence of Requirement R5, Measure M5 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 Transmission Owner and Generator Owner as applicable shall retain evidence of Requirement R13, Measure 13 for five calendar years.

If a Transmission Owner, Generator Owner, or Reliability Coordinator 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.

Violation Severity Levels

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 owners that their BES Elements require SER or FR data by 10 calendar days or less.	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 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 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than 10 calendar	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 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 1.2 was late in notifying the other owners that their BES Elements require SER or FR data by greater than	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 that their BES Elements require SER or FR data by greater than 30 calendar days.

				days, but less than or equal to 20 calendar days.	20 calendar days, but less than or equal to 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 quantities, which is the product of the total number of monitored BES Elements and the number of specified 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 electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified 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 60 percent, but less than or equal to 70 percent of the total set of required electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical	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, which is the product of the total number of monitored BES Elements and the number of specified electrical

			quantities for each BES Element.	quantities for each BES Element.	quantities for each BES Element.	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 Reliability Coordinator 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. OR The Reliability Coordinator 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.	The Reliability Coordinator 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. OR The Reliability Coordinator 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	The Reliability Coordinator 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. OR The Reliability Coordinator 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	The Reliability Coordinator 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 The Reliability Coordinator 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 Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by 10 calendar days or less.	days and less than or equal to 60 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 10 calendar days, but less than or equal to 20 calendar days.	than or equal to 90 calendar days. OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying the owners that their BES Elements require DDR data by greater than 20 calendar days, but less than or equal to 30 calendar days.	OR The Reliability Coordinator as directed by Requirement R5, Part 5.3 was late in notifying one or more owners that their BES Elements require DDR data by greater than 30 calendar days. OR The Reliability Coordinator 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 total required electrical quantities for all applicable BES Elements.	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 total required electrical quantities for all applicable BES Elements.	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 total required electrical quantities for all applicable BES Elements.	The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.

			more than 80 percent, but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	70 percent, but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	60 percent, but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	
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	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts	The Transmission Owner or Generator Owner failed to have time synchronization per

			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.	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.	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.	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 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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.	The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.2 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

			OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 90 percent of the data, but less than 100 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 80 percent of the data, but less than or equal to 90 percent of the data in the proper data format.	OR The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more than 70 percent of the data, but less than or equal to 80 percent of the data in the proper data format.	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 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.

R13	Long-term Planning	Lower		The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by less than or equal to 6 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by less than or equal to 6 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 6 months but less than or equal to 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 6 months but less than or equal to 12 months.	The Transmission Owner or Generator Owner had data, as applicable, for the BES buses identified during the re-evaluation per Requirement R1, Part 1.3 and was late by greater than 12 months. OR The Transmission Owner or Generator Owner had data, as applicable, for the BES Elements identified during the re-evaluation per Requirement R5, Part 5.4 and was late by greater than 12 months.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC Reliability Standard PRC-002-4: Implementation Plan.

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.

NERC Reliability Standard PRC-002-4: Technical Rationale.

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	
3	May 13, 2021	Adopted by NERC Board of Trustees	Revised
4	February 16,2023	Adopted by NERC Board of Trustees	Revised under Project 2021-04
4	April 14,2023	FERC Order Approving PRC-002-4 Docket No. RD23-4-000.	
4	April 14,2023	Effective Date	April 1,2024

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.

During re-evaluation per Requirement R1, Part 1.3, if the three phase short circuit MVA of the newly identified BES bus is within 15% of the three phase short circuit MVA of the currently applicable BES bus with SER and FR data then it is not necessary to change the applicable BES bus. Proceed to Step 9.

<u>If the list has more than 11 BES buses:</u> 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[3]

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

[3] "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	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

Requirement	Entity	Implementation
R13	TO | GO	X

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-6.1

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date*:**

* Mandatory BC Effective Date: April 1, 2026

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes at a minimum the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions and Real-time monitoring. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions and Real-time monitoring. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority:
The British Columbia Utilities Commission.

1.2 Evidence Retention: The following evidence retention period(s) 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.

Each responsible entity 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.

Each Transmission Operator shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.
R2	Operations Planning	Lower	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions and Real- time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions and Real- time	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions and Real- time monitoring.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions and Real- time monitoring.

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				monitoring.		OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions and Real- time monitoring.
For the Requirement R3 and R4 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.						
R3	Operations Planning	Lower	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	Operations Planning	Lower	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that	The Balancing Authority did not distribute its Specification(s) to three entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			by the Balancing Authority's analysis functions and Real-time monitoring.	have data and information required by the Balancing Authority's analysis functions and Real-time monitoring.	have data and information required by the Balancing Authority's analysis functions and Real-time monitoring.	the Balancing Authority's analysis functions and Real-time monitoring.
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances
None.

E. Interpretations
None.

F. Associated Documents
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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23,2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025