BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER R-1-13

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Mandatory Reliability Standards Assessment Report No. 5
by British Columbia Hydro and Power Authority
and the Determination of Reliability Standards for Adoption in British Columbia

BEFORE: L.F. Kelsey, Commissioner
D.M. Morton, Commissioner January 15, 2013

ORDER

WHEREAS:

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

B. Ministerial Order No. MO39 dated February 22, 2009, made a Mandatory Reliability Standards Regulation which prescribes the parties that are subject to reliability standards adopted under section 125.2(6) of the Act;

C. In order to facilitate the Commission's consideration of reliability standards, British Columbia Hydro and Power Authority (BC Hydro) is required under section 125.2(3) of the Act to review each reliability standard and provide the Commission with a report assessing:

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

(b) the suitability of the reliability standard for British Columbia,

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

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

D. The approach taken to evaluate reliability standards has not changed from that used in previous MRS Assessment reports. In those reports, the NERC and WECC standards were viewed as having two components. The first component determines applicability and mandates the types of activities that are required to maintain system reliability. As per Assessment Report No. 1 dated March 27, 2009, British Columbia Transmission Corporation (now BC Hydro) was of the view that this portion alone is the "reliability standard" contemplated in Section 125.2 of the Act, and is therefore the only component of the reliability standard assessed by BC Hydro. The second component includes the compliance provisions, which are not assessed by BC Hydro;

E. The Act does not provide for alterations of reliability standards prior to their adoption in BC;

F. On April 19, 2012, BC Hydro filed Mandatory Reliability Standards Assessment Report No. 5 (Report) pursuant to section 125.2(3) of the Act, assessing three new reliability standards, seven replacement reliability standards and 21 revised reliability standards (three of which include interim versions) developed by the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). BC Hydro assessed the reliability standards excluding the accompanying compliance provisions. On May 3, 2012, BC Hydro filed Errata to Table 3 of the Report. The existing Commission approved reliability standards to be superseded by replacement or revised standards were adopted in BC under Order Nos. G-67-09, G-167-10, G-162-11 and G-175-11;

G. BC Hydro concluded that the three new reliability standards, the seven replacement reliability standards and the final versions of the 21 revised reliability standards (including the three interim versions) are suitable for adoption in BC;

H. The NERC Glossary of Terms dated December 13, 2011 was included in the Report assessed by BC Hydro. Some but not all of the definitions were accompanied by a FERC approval date;

I. Order G-162-11 had previously adopted the NERC Glossary of Terms dated August 4, 2011;

J. Pursuant to section 125.2(5)(a) of the Act, the Commission posted the Report on its website at www.bcuc.com and by Order R-54-12 dated September 13, 2012, directed BC Hydro to publish a Notice of Mandatory Reliability Standards Assessment Report No. 5 and Process for Public Comments, and established the Regulatory Timetable for comments;

K. Comments were received from Shell Energy North America (Canada) Inc. and Shell Energy North America (US), L.P. (together Shell Energy) and FortisBC Inc.;

L. On October 26, 2012, BC Hydro provided comments in response;

M. On November 9, 2012 Commission Staff IRs were issued to BC Hydro;

N. On November 30, 2012 BC Hydro provided response to Commission Staff IRs;

O. Shell Energy argued that standards should be altered to comport with the reliability needs in BC. As an example they cited Standards IRO-005-2a, IRO-005-3a, TOP-005-1.1a and TOP-005-2a which contain references to Purchasing-Selling Entities (PSE's) which Shell asserts are not relevant to reliability or the role PSE's play within the electric system and suggests that NERC is revising standards to recognize that. In Response (October 26, 2012) BC Hydro noted that the Act does not provide for alterations to standards and that the standard revisions referred to by Shell were not approved by FERC in the period covered by the Assessment Report;

P. FortisBC Inc. agreed with BC Hydro's position that the compliance provisions should not form part of the approved BC standard and for the same reasons recommended the Violation Risk Factors and Violation Severity Levels be struck through when they appear in sections of the standard other than section D (Compliance Provisions). The Commission has acknowledged that the compliance provisions are not part of the standards assessed by BC Hydro. Furthermore the Commission does not have the authority to alter reliability standards prior to their adoption in BC;

Q. Pursuant to section 125.2 (6) of the Act, the Commission must adopt the reliability standards addressed in the report if the commission considers that the reliability standards are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliability standards;

R. The Commission has reviewed and considered the Report and the reliability standards assessed in it, as well as the comments received. The Commission determines that the standards assessed in BC Hydro's Mandatory Reliability Standards Assessment Report No. 5 are in the public interest and should be adopted in BC to maintain or achieve consistency with other jurisdictions that have adopted the reliability standards, subject to the terms of this Order;

S. The Commission considers the compliance provisions of the reliability standards helpful for compliance monitoring in BC;

T. The Commission considers that the NERC Glossary of Terms dated December 13, 2011 should be adopted, except for those definitions which have not been approved by the U.S. Federal Energy Reliability Commission;

U. The Commission considers that it is appropriate to provide effective dates for entities to come into compliance with the reliability standards to be adopted in this Order.

NOW THEREFORE the Commission orders as follows:

1. The effective date for each reliability standard adopted in this Order is the date appearing in the table found in Appendix A to this Order (the Effective Date).

2. The Commission adopts the three new reliability standards listed in the table found in Appendix A to this Order. These new standards' Effective Dates shall be as provided in Directive 1.

3. The Commission adopts the seven reliability replacement standards listed in the table found in Appendix A to this Order. The replacement reliability standards' Effective Dates shall be as provided in Directive 1. The eight Commission approved reliability standards listed in the table found in Appendix A to this Order shall remain in effect until superseded on the Effective Date by the corresponding replacement reliability standard.

4. The Commission adopts the three interim versions of revised reliability standards listed in the table found in Appendix A to this Order. These interim versions, although adopted, shall not become effective because they will be superseded on the Effective Date by a more recent revision of the corresponding reliability standard assessed by BC Hydro in the Report.

5. The Commission adopts the 21 revised reliability standards listed in the table found in Appendix A to this Order. These revised reliability standards' Effective Dates shall be as provided in Directive 1. The 21 Commission approved reliability standards listed in the table found in Appendix A to this Order shall remain in effect until superseded on the Effective Date by the corresponding revised reliability standard.

6. Appendix B to this Order contains the text of the standards adopted by this Order.

7. The Commission directs that individual requirements within reliability standards that incorporate by reference reliability standards that have not been adopted by the Commission are of no force or effect.

8. The Commission adopts the NERC Glossary of Terms Used in Reliability Standards, dated December 13, 2011, that defines the terms employed in the reliability standards and is posted to the WECC and NERC websites, to be effective as of the date of this Order.

9. The Commission directs that definitions within the NERC Glossary of Terms Used in Reliability Standards, dated December 13, 2011, which have not been approved by the U.S. Federal Energy Reliability Commission, are of no force or effect.

10. The Commission adopts the Compliance Provisions, as defined in the Rules of Procedure for Reliability Standards in BC, that accompany each of the adopted BC reliability standards, in the form directed by the Commission to be posted on the WECC website, as amended from time to time.

11. As a result of this Order and Orders G-67-09, G-167-10, G-162-11 and G-175-11, the standards listed in the table found in Appendix C to this Order are the reliability standards adopted in BC.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of January 2013.

BY ORDER

Original signed by:

D.M. Morton
Commissioner

Attachments

British Columbia Utilities Commission

Reliability Standards with Effective Dates as adopted by this Order

Standards	Standard Name	Effective Date	Type	Commission Approved Standard to be Superseded[1]
BAL-006-2	Inadvertent Interchange	3 months after BCUC approval	Revised	BAL-006-1.1
CIP-001-1a	Sabotage Reporting	Not Applicable	Interim Version	-
CIP-001-2a*	Sabotage Reporting	Immediately after BCUC approval. ERCOT regional variance does not apply to B.C.	Revised	CIP-001-1
CIP-005-3a	Cyber Security -Electronic Security Perimeter(s)	6 months after BCUC approval	Revised	CIP-005-3
EOP-002-3	Capacity and Energy Emergencies	6 months after BCUC approval	Revised	EOP-002-2.1
FAC-002-1	Coordination of Plans For New Generation, Transmission, and End-User	6 months after BCUC approval	Revised	FAC-002-0
FAC-501-WECC-1	Transmission Maintenance	3 months after BCUC approval	Replacement	PRC-STD-005-1
INT-003-3	Interchange Transaction Implementation	3 months after BCUC approval	Revised	INT-003-2
IRO-002-2	Reliability Coordination -Facilities	3 months after BCUC approval	Revised	IRO-002-1
IRO-004-2	Reliability Coordination -Operations Planning	3 months after BCUC approval	Revised	IRO-004-1
IRO-005-2a	Reliability Coordination -Current Day Operations	Not Applicable	Interim Version	-
IRO-005-3a *	Reliability Coordination -Current Day Operations	3 months after BCUC approval	Revised	IRO-005-2
IRO-006-5	Reliability Coordination -Transmission Loading Relief (TLR)	3 months after BCUC approval	Revised	IRO-006-4.1
IRO-006-WECC-1	Qualified Transfer Path Unscheduled Flow (USF) Relief	3 months after BCUC approval	Replacement	IRO-STD-006-0
IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments	3 months after BCUC approval	New	
IRO-009-1	Reliability Coordinator Actions to Operate Within IROLs	3 months after BCUC approval	New	
IRO-010-1a	Reliability Coordinator Data Specification and Collection	3 months after BCUC approval	New	
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts.	3 months after BCUC approval	Revised	MOD-021-0.1
PER-004-2	Reliability Coordination -Staffing	Immediately after BCUC approval	Revised	PER-004-1 (Requirements 1 and 5)

[1] Commission Approved Standard to be Superseded by replacement or revised standard assessed in MRS Assessment Report No. 5
*Identifies final version of a standard that was revised twice during the assessment period

Standards	Standard Name	Effective Date	Type	Commission Approved Standard to be Superseded[1]
PER-005-1	System Personnel Training	**R1, R2**: 24 months after BCUC Approval **R3**: 18 months after BCUC Approval. **R3.1**: 36 months after BCUC Approval	Replacement	PER-002-0 & PER-004-1 (Requirements 2, 3 and 4)
PRC-004-1a	Analysis and Mitigation of Transmission and Generation Protection System Misoperations	3 months after BCUC approval	Revised	PRC-004-1
PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation	6 months after BCUC approval	Replacement	PRC-STD-001-1 & PRC-STD-003-1
PRC-005-1a	Transmission and Generation Protection System Maintenance and Testing	3 months after BCUC approval	Revised	PRC-005-1
TOP-001-1a	Reliability Responsibilities and Authorities	Immediately after BCUC approval	Revised	TOP-001-1
TOP-002-2b	Normal Operations Planning	Immediately after BCUC approval	Revised	TOP-002-2a
TOP-003-1	Planned Outage Coordination	3 months after BCUC approval	Revised	TOP-003-0
TOP-005-1.1a	Operational Reliability Information	Not Applicable	Interim Version	-
TOP-005-2a *	Operational Reliability Information	3 months after BCUC approval	Revised	TOP-005-1.1
TOP-006-2	Monitoring System Conditions	3 months after BCUC approval	Revised	TOP-006-1
TOP-007-WECC-1	System Operating Limits	3 months after BCUC approval	Replacement	TOP-STD-007-0
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	Immediately after BCUC approval	Revised	TPL-002-0a
VAR-001-2	Voltage and Reactive Control	6 months after BCUC approval	Revised	VAR-001-1
VAR-002-WECC-1	Automatic Voltage Regulators (AVR)	12 months after BCUC approval	Replacement	VAR-STD-002a-1
VAR-501-WECC-1	Power System Stabilizer (PSS)	3 months after BCUC approval	Replacement	VAR-STD-002b-1

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[1] Commission Approved Standard to be Superseded by replacement or revised standard assessed in MRS Assessment Report No. 5
*Identifies final version of a standard that was revised twice during the assessment period

A. Introduction

1. **Title:** **Inadvertent Interchange**
2. **Number:** BAL-006-2
3. **Purpose:**

   This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.
4. **Applicability:**

   4.1. Balancing Authorities.
5. ***Effective Date:** First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, first day of first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange. (*Violation Risk Factor: Lower*)

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators. (*Violation Risk Factor: Lower*)

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities. (*Violation Risk Factor: Lower*)

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Actual Net Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following: (*Violation Risk Factor: Lower*)

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to: (*Violation Risk Factor: Lower*)

R4.1.1. The hourly values of Net Interchange Schedule. (*Violation Risk Factor: Lower*)

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange. (*Violation Risk Factor: Lower*)

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month. (*Violation Risk Factor: Lower*)

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies). (*Violation Risk Factor: Lower*)

R5. Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. (*Violation Risk Factor: Lower*)

C. Measures

None specified.

D. Compliance

Compliance Monitoring Authority

The British Columbia Utilities Commission

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.

1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.

1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	Each Balancing Authority failed to calculate and record hourly Inadvertent Interchange.
R2.	N/A	N/A	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. OR Failed to take into account interchange served by jointly owned generators.	The Balancing Authority failed to include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. AND Failed to take into account interchange served by jointly owned generators.
R3.	N/A	N/A	N/A	The Balancing Authority failed to ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.
R4.	The Balancing Authority failed to record Actual Net Interchange values that are equal but opposite in sign to its Adjacent Balancing Authorities.	The Balancing Authority failed to compute Inadvertent Interchange.	The Balancing Authority failed to operate to a common Net Interchange Schedule that is equal but opposite to its Adjacent Balancing Authorities.	N/A

Standard BAL-006-2 — Inadvertent Interchange

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule. AND The hourly integrated megawatt-hour values of Net Actual Interchange.
R4.1.1.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly values of Net Interchanged Schedule.
R4.1.2.	N/A	N/A	N/A	The Balancing Authority, by the end of the next business day, failed to agree with its Adjacent Balancing Authorities to the hourly integrated megawatt-hour values of Net Actual Interchange.
R4.2.	N/A	N/A	N/A	The Balancing Authority failed to use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-

Standard BAL-006-2 — Inadvertent Interchange

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Peak and Off-Peak hours of the month.
R4.3.	N/A	N/A	N/A	The Balancing Authority failed to make after-the-fact corrections to the agreed-to daily and monthly accounting data to reflect actual operating conditions or changes or corrections based on non-reliability considerations were reflected in the Balancing Authority's Inadvertent Interchange.
R5.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities, submitted a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute but failed to provide a process for correcting the discrepancy.	Adjacent Balancing Authorities that could not mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month, failed to submit a report to their respective Regional Reliability Organizations Survey Contact describing the nature and the cause of the dispute as well as a process for correcting the discrepancy.	N/A	N/A

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

E. Regional Differences

1. Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004includes SPP effective May 1, 2006.

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	April 6, 2006	Added following to "Effective Date:" This standard will expire for one year beyond the effective date or when replaced by a new version of BAL-006, whichever comes first.	Errata
2	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO from list of entities with an Inadvertent Interchange Accounting Waiver (Project 2009-18).	Revision
2	November 5, 2009	Approved by the Board of Trustees	
2	January 6, 2011	Approved by FERC	

Standard CIP-001-1a — Sabotage Reporting

A. Introduction

1. **Title:** **Sabotage Reporting**
2. **Number:** CIP-001-1a
3. **Purpose:** Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
   - **4.5.** Load Serving Entities.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

C. Measures

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement 1

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements 2 and 3.

***Mandatory BC effective date: Not applicable as per BCUC Order R-1-13**

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to procedures, policies, a letter of understanding, communication records, or other equivalent evidence that will be used to confirm that it has established communications contacts with the applicable, local FBI or RCMP officials to communicate sabotage events (Requirement 4).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

Each Reliability Coordinator, Transmission Operator, Generator Operator, Distribution Provider, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: There shall be a separate Level 1 non-compliance, for every one of the following requirements that is in violation:

2.1.1 Does not have procedures for the recognition of and for making its operating personnel aware of sabotage events (R1).

2.1.2 Does not have procedures or guidelines for the communication of information concerning sabotage events to appropriate parties in the Interconnection (R2).

2.1.3 Has not established communications contacts, as specified in R4.

2.2. Level 2: Not applicable.

2.3. Level 3: Has not provided its operating personnel with sabotage response procedures or guidelines (R3).

2.4. Level 4:.Not applicable.

E. Regional Differences

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	November 1, 2006	Adopted by Board of Trustees	Amended
1	April 4, 2007	Regulatory Approval — Effective Date	New
1a	February 16, 2010	Added Appendix 1 — Interpretation of R2 approved by the NERC Board of Trustees	Addition
1a	February 2, 2011	Interpretation of R2 approved by FERC on February 2, 2011	Same addition

Appendix 1

Requirement Number and Text of Requirement
CIP-001-1: **R2**. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.
Question
Please clarify what is meant by the term, "appropriate parties." Moreover, who within the Interconnection hierarchy deems parties to be appropriate?
Response
The drafting team interprets the phrase "appropriate parties in the Interconnection" to refer collectively to entities with whom the reporting party has responsibilities and/or obligations for the communication of physical or cyber security event information. For example, reporting responsibilities result from NERC standards IRO-001 Reliability Coordination — Responsibilities and Authorities, COM-002-2 Communication and Coordination, and TOP-001 Reliability Responsibilities and Authorities, among others. Obligations to report could also result from agreements, processes, or procedures with other parties, such as may be found in operating agreements and interconnection agreements. The drafting team asserts that those entities to which communicating sabotage events is appropriate would be identified by the reporting entity and documented within the procedure required in CIP-001-1 Requirement R2. Regarding "who within the Interconnection hierarchy deems parties to be appropriate," the drafting team knows of no interconnection authority that has such a role.

***Mandatory BC effective date: Not applicable as per BCUC Order R-1-13**

A. Introduction

1. **Title:** **Sabotage Reporting**
2. **Number:** CIP-001-2a
3. **Purpose:** Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Generator Operators.
   - **4.5.** Load Serving Entities.
   - **4.6.** Transmission Owners (only in ERCOT Region).
   - **4.7.** Generator Owners (only in ERCOT Region).
5. ***Effective Date:** ERCOT Regional Variance will be effective the first day of the first calendar quarter after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

C. Measures

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement 1

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements 2 and 3.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to procedures, policies, a letter of understanding, communication records, or other equivalent evidence that will be used to confirm that it has established communications contacts with the applicable, local FBI or RCMP officials to communicate sabotage events (Requirement 4).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

Each Reliability Coordinator, Transmission Operator, Generator Operator, Distribution Provider, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: There shall be a separate Level 1 non-compliance, for every one of the following requirements that is in violation:

2.1.1 Does not have procedures for the recognition of and for making its operating personnel aware of sabotage events (R1).

2.1.2 Does not have procedures or guidelines for the communication of information concerning sabotage events to appropriate parties in the Interconnection (R2).

2.1.3 Has not established communications contacts, as specified in R4.

2.2. Level 2: Not applicable.

2.3. Level 3: Has not provided its operating personnel with sabotage response procedures or guidelines (R3).

2.4. Level 4:.Not applicable.

E. ERCOT Interconnection-wide Regional Variance

Requirements

EA.1. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.

EA.2. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.

EA.3. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.

EA.4. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall establish communications contacts with local Federal Bureau of Investigation (FBI) officials and develop reporting procedures as appropriate to their circumstances.

Measures

M.A.1. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have and provide upon request a procedure (either electronic or hard copy) as defined in Requirement EA1.

M.A.2. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirements EA2 and EA3.

M.A.3. Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, procedures, policies, a letter of understanding, communication records, or other equivalent evidence that will be used to confirm that it has established communications contacts with the local FBI officials to communicate sabotage events (Requirement EA4).

Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity shall be responsible for compliance monitoring.

1.2. Data Retention

Each Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load Serving Entity shall have current, in-force documents available as evidence of compliance as specified in each of the Measures.

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

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

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

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Amended
1	April 4, 2007	Regulatory Approval — Effective Date	New
1a	February 16, 2010	Added Appendix 1 — Interpretation of R2 approved by the NERC Board of Trustees	Addition
1a	February 2, 2011	Interpretation of R2 approved by FERC on February 2, 2011	Same addition
	June 10, 2010	TRE regional ballot approved variance	By Texas RE
	August 24, 2010	Regional Variance Approved by Texas RE Board of Directors	
2a	February 16, 2011	Approved by NERC Board of Trustees	
2a	August 2, 2011	FERC Order issued approving Texas RE Regional Variance	

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

Appendix 1

Requirement Number and Text of Requirement
CIP-001-1: **R2**. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.
Question
Please clarify what is meant by the term, "appropriate parties." Moreover, who within the Interconnection hierarchy deems parties to be appropriate?
Response
The drafting team interprets the phrase "appropriate parties in the Interconnection" to refer collectively to entities with whom the reporting party has responsibilities and/or obligations for the communication of physical or cyber security event information. For example, reporting responsibilities result from NERC standards IRO-001 Reliability Coordination — Responsibilities and Authorities, COM-002-2 Communication and Coordination, and TOP-001 Reliability Responsibilities and Authorities, among others. Obligations to report could also result from agreements, processes, or procedures with other parties, such as may be found in operating agreements and interconnection agreements. The drafting team asserts that those entities to which communicating sabotage events is appropriate would be identified by the reporting entity and documented within the procedure required in CIP-001-1 Requirement R2. Regarding "who within the Interconnection hierarchy deems parties to be appropriate," the drafting team knows of no interconnection authority that has such a role.

A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)

2. **Number:** CIP-005-3a

3. **Purpose:** Standard CIP-005-3 requires the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter. Standard CIP-005-3 should be read as part of a group of standards numbered Standards CIP-002-3 through CIP-009-3.

4. **Applicability**

   4.1. Within the text of Standard CIP-005-3, “Responsible Entity” shall mean:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Interchange Authority.

   4.1.4 Transmission Service Provider.

   4.1.5 Transmission Owner.

   4.1.6 Transmission Operator.

   4.1.7 Generator Owner.

   4.1.8 Generator Operator.

   4.1.9 Load Serving Entity.

   4.1.10 NERC.

   4.1.11 Regional Entity

   4.2. The following are exempt from Standard CIP-005-3:

   4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.

   4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

   4.2.3 Responsible Entities that, in compliance with Standard CIP-002-3, identify that they have no Critical Cyber Assets.

5. ***Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. Electronic Security Perimeter — The Responsible Entity shall ensure that every Critical Cyber Asset resides within an Electronic Security Perimeter. The Responsible Entity shall identify and document the Electronic Security Perimeter(s) and all access points to the perimeter(s).

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

R1.1. Access points to the Electronic Security Perimeter(s) shall include any externally connected communication end point (for example, dial-up modems) terminating at any device within the Electronic Security Perimeter(s).

R1.2. For a dial-up accessible Critical Cyber Asset that uses a non-routable protocol, the Responsible Entity shall define an Electronic Security Perimeter for that single access point at the dial-up device.

R1.3. Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).

R1.4. Any non-critical Cyber Asset within a defined Electronic Security Perimeter shall be identified and protected pursuant to the requirements of Standard CIP-005-3.

R1.5. Cyber Assets used in the access control and/or monitoring of the Electronic Security Perimeter(s) shall be afforded the protective measures as a specified in Standard CIP-003-3; Standard CIP-004-3 Requirement R3; Standard CIP-005-3 Requirements R2 and R3; Standard CIP-006-3 Requirement R3; Standard CIP-007-3 Requirements R1 and R3 through R9; Standard CIP-008-3; and Standard CIP-009-3.

R1.6. The Responsible Entity shall maintain documentation of Electronic Security Perimeter(s), all interconnected Critical and non-critical Cyber Assets within the Electronic Security Perimeter(s), all electronic access points to the Electronic Security Perimeter(s) and the Cyber Assets deployed for the access control and monitoring of these access points.

R2. Electronic Access Controls — The Responsible Entity shall implement and document the organizational processes and technical and procedural mechanisms for control of electronic access at all electronic access points to the Electronic Security Perimeter(s).

R2.1. These processes and mechanisms shall use an access control model that denies access by default, such that explicit access permissions must be specified.

R2.2. At all access points to the Electronic Security Perimeter(s), the Responsible Entity shall enable only ports and services required for operations and for monitoring Cyber Assets within the Electronic Security Perimeter, and shall document, individually or by specified grouping, the configuration of those ports and services.

R2.3. The Responsible Entity shall implement and maintain a procedure for securing dial-up access to the Electronic Security Perimeter(s).

R2.4. Where external interactive access into the Electronic Security Perimeter has been enabled, the Responsible Entity shall implement strong procedural or technical controls at the access points to ensure authenticity of the accessing party, where technically feasible.

R2.5. The required documentation shall, at least, identify and describe:

R2.5.1. The processes for access request and authorization.

R2.5.2. The authentication methods.

R2.5.3. The review process for authorization rights, in accordance with Standard CIP-004-3 Requirement R4.

R2.5.4. The controls used to secure dial-up accessible connections.

R2.6. Appropriate Use Banner — Where technically feasible, electronic access control devices shall display an appropriate use banner on the user screen upon all interactive access attempts. The Responsible Entity shall maintain a document identifying the content of the banner.

R3. Monitoring Electronic Access — The Responsible Entity shall implement and document an electronic or manual process(es) for monitoring and logging access at access points to the Electronic Security Perimeter(s) twenty-four hours a day, seven days a week.

R3.1. For dial-up accessible Critical Cyber Assets that use non-routable protocols, the Responsible Entity shall implement and document monitoring process(es) at each access point to the dial-up device, where technically feasible.

R3.2. Where technically feasible, the security monitoring process(es) shall detect and alert for attempts at or actual unauthorized accesses. These alerts shall provide for appropriate notification to designated response personnel. Where alerting is not technically feasible, the Responsible Entity shall review or otherwise assess access logs for attempts at or actual unauthorized accesses at least every ninety calendar days.

R4. Cyber Vulnerability Assessment — The Responsible Entity shall perform a cyber vulnerability assessment of the electronic access points to the Electronic Security Perimeter(s) at least annually. The vulnerability assessment shall include, at a minimum, the following:

R4.1. A document identifying the vulnerability assessment process;

R4.2. A review to verify that only ports and services required for operations at these access points are enabled;

R4.3. The discovery of all access points to the Electronic Security Perimeter;

R4.4. A review of controls for default accounts, passwords, and network management community strings;

R4.5. Documentation of the results of the assessment, the action plan to remediate or mitigate vulnerabilities identified in the assessment, and the execution status of that action plan.

R5. Documentation Review and Maintenance — The Responsible Entity shall review, update, and maintain all documentation to support compliance with the requirements of Standard CIP-005-3.

R5.1. The Responsible Entity shall ensure that all documentation required by Standard CIP-005-3 reflect current configurations and processes and shall review the documents and procedures referenced in Standard CIP-005-3 at least annually.

R5.2. The Responsible Entity shall update the documentation to reflect the modification of the network or controls within ninety calendar days of the change.

R5.3. The Responsible Entity shall retain electronic access logs for at least ninety calendar days. Logs related to reportable incidents shall be kept in accordance with the requirements of Standard CIP-008-3.

C. Measures

M1. The Responsible Entity shall make available documentation about the Electronic Security Perimeter as specified in Requirement R1.

M2. The Responsible Entity shall make available documentation of the electronic access controls to the Electronic Security Perimeter(s), as specified in Requirement R2.

M3. The Responsible Entity shall make available documentation of controls implemented to log and monitor access to the Electronic Security Perimeter(s) as specified in Requirement R3.

M4. The Responsible Entity shall make available documentation of its annual vulnerability assessment as specified in Requirement R4.

M5. The Responsible Entity shall make available access logs and documentation of review, changes, and log retention as specified in Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

1.4.1 The Responsible Entity shall keep logs for a minimum of ninety calendar days, unless: a) longer retention is required pursuant to Standard CIP-008-3, Requirement R2; b) directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Responsible Entity shall keep other documents and records required by Standard CIP-005-3 from the previous full calendar year.

1.4.3 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	D.2.3.1 — Change "Critical Assets," to "Critical Cyber Assets" as intended.	03/24/06
2		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. Revised the wording of the Electronic Access Controls requirement stated in R2.3 to clarify that the Responsible Entity shall "implement and maintain" a procedure for securing dial-up access to the Electronic Security Perimeter(s). Changed compliance monitor to Compliance Enforcement Authority.	
3		Update version from -2 to -3	
3	12/16/09	Approved by the NERC Board of Trustees	Update
3a	02/16/10	Added Appendix 1 – Interpretation of R1.3 approved by BOT on February 16, 2010	Interpretation
3a	02/02/11	Approved by FERC	

Appendix 1

Requirement Number and Text of Requirement
Section 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters. **Requirement R1.3** Communication links connecting discrete Electronic Security Perimeters shall not be considered part of the Electronic Security Perimeter. However, end points of these communication links within the Electronic Security Perimeter(s) shall be considered access points to the Electronic Security Perimeter(s).
Question 1 (Section 4.2.2)
What kind of cyber assets are referenced in 4.2.2 as "associated"? What else could be meant except the devices forming the communication link?
Response to Question 1
In the context of applicability, associated Cyber Assets refer to any communications devices external to the Electronic Security Perimeter, i.e., beyond the point at which access to the Electronic Security Perimeter is controlled. Devices controlling access into the Electronic Security Perimeter are not exempt.
Question 2 (Section 4.2.2)
Is the communication link physical or logical? Where does it begin and terminate?
Response to Question 2
The drafting team interprets the data communication link to be physical or logical, and its termination points depend upon the design and architecture of the communication link.
Question 3 (Requirement R1.3)
Please clarify what is meant by an “endpoint”? Is it physical termination? Logical termination of OSI layer 2, layer 3, or above?
Response to Question 3
The drafting team interprets the endpoint to mean the device at which a physical or logical

communication link terminates. The endpoint is the Electronic Security Perimeter access point if access into the Electronic Security Perimeter is controlled at the endpoint, irrespective of which Open Systems Interconnection (OSI) layer is managing the communication.
Question 4 (Requirement R1.3)
If "endpoint" is defined as logical and refers to layer 3 and above, please clarify if the termination points of an encrypted tunnel (layer 3) must be treated as an "access point? If two control centers are owned and managed by the same entity, connected via an encrypted link by properly applied Federal Information Processing Standards, with tunnel termination points that are within the control center ESPs and PSPs and do not terminate on the firewall but on a separate internal device, and the encrypted traffic already passes through a firewall access point at each ESP boundary where port/protocol restrictions are applied, must these encrypted communication tunnel termination points be treated as "access points" in addition to the firewalls through which the encrypted traffic has already passed?
Response to Question 4
In the case where the "endpoint" is defined as logical and is >= layer 3, the termination points of an encrypted tunnel must be treated as an "access point." The encrypted communication tunnel termination points referred to above are "access points."

Standard EOP-002-3 — Capacity and Energy Emergencies

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**
2. **Number**: EOP-002-3
3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   - **4.1.** Balancing Authorities.
   - **4.2.** Reliability Coordinators.
   - **4.3.** Load-Serving Entities.
5. ***(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan, , to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

Standard EOP-002-3 — Capacity and Energy Emergencies

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Interrupting interruptible load and exports.

R6.4. Requesting emergency assistance from other Balancing Authorities.

R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

Standard EOP-002-3 — Capacity and Energy Emergencies

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall 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, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall 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 other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall 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 other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Timeframe

1.3. Not Applicable. **Compliance Monitoring and Enforcement Process**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep
The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

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

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

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

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.

Attachment 1-EOP-002-2.1
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

- When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The

Standard EOP-002-3 — Capacity and Energy Emergencies

Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

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

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
    - Public appeals to reduce demand.
    - Voltage reduction.
    - Interruption of non-firm end use loads in accordance with applicable contracts[1].
    - Demand-side management.
    - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

[1] For emergency, not economic, reasons.

Standard EOP-002-3 — Capacity and Energy Emergencies

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

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

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 **Mitigation of cascading failures**. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 **Returning to pre-emergency Operating Security Limits.** Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 **Notification of other parties.** Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 **Reporting.** Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. **Alert 0 - Termination.** When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. **Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. **Energy Emergency Alert 3 Report**

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Standard EOP-002-3 — Capacity and Energy Emergencies

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By:	**Organization:**
Title:	

Standard FAC-002-1 — Coordination of Plans for New Facilities

A. Introduction

1. **Title:** Coordination of Plans For New Generation, Transmission, and End-User Facilities

2. **Number:** FAC-002-1

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. ***(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

C. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting

Complaints

1.4. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.5. Additional Compliance Information

None

2. Violation Severity Levels (no changes)

E. Regional Differences

Standard FAC-002-1 — Coordination of Plans for New Facilities

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of “Regional Reliability Organizations(s).	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 693.	Revised.

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

WECC Standard FAC-501-WECC-1 – Transmission Maintenance

A. Introduction

1. **Title:** Transmission Maintenance
2. **Number:** FAC-501-WECC-1
3. **Purpose:** To ensure the Transmission Owner of a transmission path identified in the table titled "Major WECC Transfer Paths in the Bulk Electric System" including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.
4. **Applicability**

   4.1. Transmission Owners that maintain the transmission paths in the most current table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:

   http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf
5. ***Effective Date:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R.1. Transmission Owners shall have a TMIP detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with each of the transmission paths identified in table titled "Major WECC Transfer Paths in the Bulk Electric System." *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R1.1. Transmission Owners shall annually review their TMIP and update as required. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R.2. Transmission Owners shall include the maintenance categories in Attachment 1-FAC-501-WECC-1 when developing their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners shall implement and follow their TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

C. Measures

M1. Transmission Owners shall have a documented TMIP per R.1.

M1.1 Transmission Owners shall have evidence they have annually reviewed their TMIP and updated as needed.

M2. Transmission Owners shall have evidence that their TMIP addresses the required maintenance details of R.2.

M3. Transmission Owners shall have records that they implemented and followed their TMIP as

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

required in R.3. The records shall include:

1. The person or crew responsible for performing the work or inspection,
2. The date(s) the work or inspection was performed,
3. The transmission facility on which the work was performed, and
4. A description of the inspection or maintenance performed.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility
The British Columbia Utilities Commission

1.2 Compliance Monitoring Period
The Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-certification conducted annually
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be one year.

1.3 Data Retention

The Transmission Owners shall keep evidence for Measure M1 through M3 for three years plus the current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

No additional compliance information.

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if any of the following conditions exist:

2.1.1 The TMIP does not include associated Facilities for one of the Paths identified in Attachment 1 FAC-501-WECC-1 as required by R.1 but Transmission Owners are performing maintenance and inspection for the missing Facilities.

2.1.2 Transmission Owners did not review their TMIP annually as required by R.1.1.

2.1.3 The TMIP does not include one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.1.4 Transmission Owners do not have maintenance and inspection records as required by R.3 but have evidence that they are implementing and following their TMIP.

2.2. **Moderate:** There shall be a Moderate Level of non-compliance if any of the following conditions exist:

2.2.1 The TMIP does not include associated Facilities for two of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.2.2 The TMIP does not include two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.2.3 Transmission Owners are not performing maintenance and inspection for one maintenance category identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.3. **High:** There shall be a High Level of non-compliance if any of the following condition exists:

2.3.1 The TMIP does not include associated Facilities for three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.3.2 The TMIP does not include three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.3.3 Transmission Owners are not performing maintenance and inspection for two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

2.4. **Severe:** There shall be a Severe Level of non-compliance if any of the following condition exists:

2.4.1 The TMIP does not include associated Facilities for more than three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.

2.4.2 The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.

2.4.3 Transmission Owners are not performing maintenance and inspection for more than two maintenance categories identified in Attachment 1 FAC-501-WECC-1 as required in R3.

WECC Standard FAC-501-WECC-1 – Transmission Maintenance

Version History – Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-005-1	
1	April 21, 2011	FERC Order issued approving FAC-501-WECC-1 (approval effective June 27, 2011)	

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Attachment 1-FAC-501-WECC-1
Transmission Line and Station Maintenance Details

The maintenance practices in the TMIP may be performance-based, time-based, conditional based, or a combination of all three. The TMIP shall include:

1. A list of Facilities and associated Elements necessary to maintain the SOL for the transfer paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System;"
2. The scheduled interval for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance activities including a description of the condition based trigger;
3. Transmission Line Maintenance Details:
   a. Patrol/Inspection
   b. Contamination Control
   c. Tower and wood pole structure management
4. Station Maintenance Details:
   a. Inspections
   b. Contamination Control
   c. Equipment Maintenance for the following:
      - Circuit Breakers
      - Power Transformers (including phase-shifting transformers)
      - Regulators
      - Reactive Devices (including, but not limited to, Shunt Capacitors, Series Capacitors, Synchronous Condensers, Shunt Reactors, and Tertiary Reactors)

A. Introduction

1. **Title:** **Interchange Transaction Implementation**

2. **Number:** INT-003-3

3. **Purpose:**

   To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations.

4. **Applicability**

   4.1. Balancing Authorities.

5. ***Effective Date:** First day of first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation. (*Violation Risk Factor: Medium*)

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on Interchange as received from the Interchange Authority, including: (*Violation Risk Factor: Lower*)

R1.1.1. Interchange Schedule start and end time. (*Violation Risk Factor: Lower*)

R1.1.2. Energy profile. (*Violation Risk Factor: Lower*)

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie. (*Violation Risk Factor: Medium*)

C. Measures

M1. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that each Interchange Schedule's start and end time, and energy profile were confirmed prior to implementation in the Balancing Authority's ACE equation. (Requirement R1, R1.1, R1.1.1 & R1.1.2)

M2. Each Receiving and Sending Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, interchange transaction tags, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts, or other equivalent evidence that will be used to confirm that it coordinated the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in Requirement 1.2.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

Each Balancing Authority shall keep 90 days of historical data (evidence).

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

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	There shall be a separate Lower VSL, if either of the following conditions exists: One instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. One instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Moderate VSL, if either of the following conditions exists: Two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate High VSL, if either of the following conditions exists: Three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	There shall be a separate Severe VSL, if either of the following conditions exists: Four or more instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2. Four or more instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2
R1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.1	The Balancing Authority experienced one instance of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced two instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced three instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	The Balancing Authority experienced four instances of entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.1.2	The Balancing Authority experienced one instance of	The Balancing Authority experienced two instances of	The Balancing Authority experienced three instances of	The Balancing Authority experienced four instances of

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
	entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.	entering a schedule into its ACE equation without confirming the schedule as specified in R1, R1.1, R1.1.1 and R1.1.2.
R1.2	The sending or receiving Balancing Authority experienced one instance of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced two instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced three instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2	The sending or receiving Balancing Authority experienced four instances of not coordinating the Interchange Schedule with the Transmission Operator of the HVDC tie as specified in R1.2

E. Regional Differences

[MISO Energy Flow Information Waiver] **dated July 16, 2003.**

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Adopted by Board of Trustees	Revised
3	November 5, 2009	Added approved VRFs and VSLs to document. Removed MISO Scheduling Agent Waiver, and MISO Enhanced Scheduling Agent Waiver (Project 2009-18).	Revised
3	November 5, 2009	Approved by the Board of Trustees	
3	January 6, 2011	Approved by FERC	

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

A. Introduction

1. **Title:** **Reliability Coordination — Facilities**

2. **Number:** IRO 002-2

3. **Purpose:** Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.

4. **Applicability**

   4.1. Reliability Coordinators.

5. ***Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after Board of Trustee adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.

R2. Each Reliability Coordinator — or its Transmission Operators and Balancing Authorities — shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.

R3. Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.

R4. Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.

R5. Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

both real and reactive power system flows, and operating reserves, and the status of Bulk Electric System elements that are or could be critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area.

R6. Each Reliability Coordinator shall have adequate analysis tools such as state estimation, pre- and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays.

R7. Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.

R8. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

C. Measures

M1. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a document that lists its voice communications facilities with Transmission Operators, Balancing Authorities and Generator Operators within its Reliability Coordinator Area and with neighboring Reliability Coordinators, that will be used to confirm that it has communication facilities in accordance with Requirements 1 and 3.

M2. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a data-link facility description document, computer print-out, training-document, or other equivalent evidence that will be used to confirm that it has data links with entities within its Reliability Coordinator Area and with neighboring Reliability Coordinators, as specified in Requirements 1 and 3.

M3. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, SCADA data collection system communications performance or equivalent evidence to demonstrate that it has real-time monitoring capability of its Reliability Coordinator Area and monitoring capability of its surrounding Reliability Coordinator Areas to identify potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations.

M4. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, documentation from suppliers, operating and planning staff training documents, examples of studies, or other equivalent evidence to show that it has analysis tools in accordance with Requirement 6.

M5. Each Reliability Coordinator shall provide evidence such as equipment specifications, operating procedures, staff records of their involvement in training, or other equivalent evidence to show that it has a backup monitoring facility that can be used to identify and monitor SOLs and IROLs. (Requirement 7)

M6. Each Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, a documented procedure or equivalent evidence that will be used to confirm that the Reliability Coordinator has the authority to veto planned outages to analysis tools, including final approvals for planned maintenance as specified in Requirement 8 Part 1.

M7. Each Reliability Coordinator shall have and provide upon request its current procedures used to mitigate the effects of analysis tool outages as specified in Requirement 8 Part 2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

Each Reliability Coordinator shall have current in-force documents used to show compliance with Measures 1 through 7.

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

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

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Reliability Coordinator has demonstrated communication facilities for both voice and data exist to all appropriate entities and that they are staffed and available but they are less than adequate.	The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with one appropriate entity or 2) Data links with one appropriate entity.	The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with two appropriate entities or 2) Data links with two appropriate entities.	The Reliability Coordinator has failed to demonstrate that is has: 1) Voice communication links with more than two appropriate entities or 2) Data links with more than two appropriate entities or 3) Communication facilities are not staffed or 4) Communication facilities are not ready.
R2	N/A	The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data with one of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.	The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data with two of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.	The Reliability Coordinator or designated Transmission Operator and Balancing Authority has failed to demonstrate it provided or arranged provision for the exchange of data with three of the other Reliability Coordinators or Transmission Operators and Balancing Authorities.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Requirement	Lower	Moderate	High	Severe
R3	N/A	The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to one of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with neighboring Reliability Coordinators.	The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to two or more of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with neighboring Reliability Coordinators.	The Reliability Coordinator has failed to demonstrate multi-directional communication capabilities to all of the Transmission Operators and Balancing Authorities in its Reliability Coordinator Area and with all neighboring Reliability Coordinators.
R4	The Reliability Coordinator's monitoring systems provide information in a way that is not easily understood and interpreted by the Reliability Coordinator's operating personnel or particular emphasis was not given to alarm management and awareness systems, automated data transfers and synchronized information systems.	The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that one potential or actual SOL or IROL violation is not identified.	The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that two or more potential and actual SOL and IROL violations are not identified.	The Reliability Coordinator has failed to demonstrate that is has detailed real-time monitoring capabilities in its Reliability Coordinator Area and sufficient monitoring capabilities of its surrounding Reliability Coordinator Areas to ensure that all potential and actual SOL and IROL violations are identified.

Requirement	Lower	Moderate	High	Severe
R5	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in one SOL violations or 2) or operating reserves for a small portion of the Reliability Authority Area.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing one IROL or to system restoration, 2) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in multiple SOL violations, or 3) operating reserves.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing two or more IROLs; or one IROL and to system restoration, 2) the status, real power flow or reactive power flow of Bulk Electric System elements that could result in multiple SOL violations and operating reserves, or 3) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing one IROL or system restoration and operating reserves.	The Reliability Coordinator failed to monitor: 1) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing all IROLs and to system restoration, or 2) the status, real power flow or reactive power flow of Bulk Electric System elements critical to assessing all SOL violations and operating reserves.

Standard IRO-002-2 — Reliability Coordination — Facilities

Requirement	Lower	Moderate	High	Severe
R6	The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing all pre-contingency flows, 2) analysis tools capable of assessing all post-contingency flows, or 3) all necessary wide-area overview displays exist.	The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing the majority of pre-contingency flows, 2) analysis tools capable of assessing the majority of post-contingency flows, or 3) the majority of necessary wide-area overview displays exist.	The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing a minority of pre-contingency flows, 2) analysis tools capable of assessing a minority of post-contingency flows, or 3) a minority of necessary wide-area overview displays exist.	The Reliability Coordinator failed to demonstrate that it has: 1) analysis tools capable of assessing any pre-contingency flows, 2) analysis tools capable of assessing any post-contingency flows, or 3) any necessary wide-area overview displays exist.
R7	The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored SOLs when the main monitoring system was unavailable or 2) it has provisions to monitor SOLs when the main monitoring system is not available.	The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored one IROL when the main monitoring system was unavailable or 2) it has provisions to monitor one IROL when the main monitoring system is not available.	The Reliability Coordinator failed to demonstrate that: 1) it or a delegated entity monitored two or more IROLs when the main monitoring system was unavailable, 2) it or a delegated entity monitored SOLs and one IROL when the main monitoring system was unavailable 3) it has provisions to monitor two or more IROLs when the main monitoring system is not available, or	**R9.** The Reliability Coordinator failed to demonstrate that it continuously monitored its Reliability Authority Area.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Requirement	Lower	Moderate	High	Severe
			4) it has provisions to monitor SOLs and one IROL when the main monitoring system was unavailable.	
R8	Reliability Coordinator has approval rights for planned maintenance outages of analysis tools but does not have approval rights for work on analysis tools that creates a greater risk of an unplanned outage of the tools.	Reliability Coordinator has approval rights for planned maintenance but does not have plans to mitigate the effects of outages of the analysis tools.	Reliability Coordinator has approval rights for planned maintenance but does not have plans to mitigate the effects of outages of the analysis tools and does not have approval rights for work on analysis tools that creates a greater risk of an unplanned outage of the tools.	Reliability Coordinator approval is not required for planned maintenance.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Deleted R2, M3 and associated compliance elements Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Corrected typographical errors in BOT approved version of VSLs	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 17, 2011	Order issued by FERC approving IRO-002-2 (approval effective 5/23/11)	

Standard IRO-004-2 — Reliability Coordination — Operations Planning

A. Introduction

1. **Title:** **Reliability Coordination — Operations Planning**

2. **Number:** IRO-004-2

3. **Purpose:** Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

   4.3. Transmission Service Providers.

5. ***Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

C. Measures

M1. None

D. Compliance

1. **Compliance Monitoring Process**

   Entities will be selected for an on-site audit at least every three years. For a selected 30-day period in the previous three calendar months prior to the on site audit, Reliability Coordinators will be asked to provide documentation showing that next-day reliability analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and Contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.

   1.1. Compliance Monitoring Responsibility

   The British Columbia Utilities Commission

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

1.2. Compliance Monitoring Period and Reset Time Frame

1.3. Data Retention

1.4. Additional Compliance Information

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

2. Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1	The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on one (1) occasion during a calendar month.	The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on two (2) to three (3) occasions during a calendar month.	The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on four (4) to five (5) occasions during a calendar month.	The responsible entity failed to comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events on more than five (5) occasions during a calendar month.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

E. Regional Variances

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		Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Retired R1 through R6, and associated Measures, Data Retention, and VSLs	Revision
2	October 17, 2008	Adopted by NERC Board of Trustees	Revision
2	March 17, 2011	FERC Order issued approving IRO-004-2 (Clarification issued on July 13, 2011)	Revision

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Standard IRO-005-2a — Reliability Coordination — Current Day Operations

A. Introduction

1. **Title:** **Reliability Coordination — Current Day Operations**
2. **Number:** IRO-005-2a
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Transmission Service Providers.
   - **4.5.** Generator Operators.
   - **4.6.** Load-Serving Entities.
   - **4.7.** Purchasing-Selling Entities.
5. ***Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

- **R1.1.** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
- **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
- **R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
- **R1.4.** System real and reactive reserves (actual versus required).
- **R1.5.** Capacity and energy adequacy conditions.
- **R1.6.** Current ACE for all its Balancing Authorities.
- **R1.7.** Current local or Transmission Loading Relief procedures in effect.
- **R1.8.** Planned generation dispatches.

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R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

R3. As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

R4. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R5. Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.

R6. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R7. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R8. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R9. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R10. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R11. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R12. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R13. Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R14. Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R15. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

R16. Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

R17. When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records, computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

M3. If a potential or actual IROL violation occurs, the Reliability Coordinator involved in the event shall 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, system event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)

M4. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)

M5. The Reliability Coordinator shall 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 it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)

M6. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.

M8. The Transmission Operators and Balancing Authorities shall 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 confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)

M9. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)

M10. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 11 Part 1)

M11. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)

M12. If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)

M13. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)

***Mandatory BC effective date: Not applicable per BCUC Order R-1-13**

M14. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

M15. The Reliability Coordinator shall 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 confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.

M16. The Reliability Coordinator shall 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 confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.

M17. The Reliability Coordinator shall 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 confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

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

1.3. Data Retention

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider shall keep 90 days of historical data (evidence).

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

2.4.1 Did not follow the Reliability Coordinator's directives in accordance with R8 Part 2).

2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

3. Levels of Non-Compliance for a Reliability Coordinator:

3.1. Level 1: Not applicable.

3.2. Level 2: Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)

3.3. Level 3: There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:

3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)

3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)

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

3.4.1 Does not meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)

3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)

3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)

3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)

3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)

3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)

3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)

3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)

3.4.10 Did not provide Transmission Service Providers with SOLs or IROLs (within the Reliability Coordinator's wide-area view) (Requirement 14 Part 1)

3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

4. Levels of Non-Compliance for a Transmission Service Provider

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

4.4.1 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)

4.4.2 Did not respect the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	February 2, 2006	Approved by Board of Trustees	Revised
2	August 31, 2006	Added three items that were inadvertently left out to "Applicability" section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities	Errata
2	November 1, 2006	Approved by Board of Trustees	Revised

2	June 26, 2007	Approved by FERC: Missing Measures and Compliance Elements	Revised
2a	November 5, 2009	Added Appendix 1 – Interpretation of R12 approved by BOT on November 5, 2009	Interpretation
2a	April 21, 2011	FERC Order issued approving Interpretation (approval effective May 26, 2011)	Interpretation

Appendix 1

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6:* New or <u>degraded</u> special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12** **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations." The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not

***Mandatory BC effective date: Not applicable per BCUC Order R-1-13**

an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. **Title:** **Reliability Coordination — Current Day Operations**
2. **Number:** IRO-005-3a
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
   - **4.1.** Reliability Coordinators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Transmission Operators.
   - **4.4.** Transmission Service Providers.
   - **4.5.** Generator Operators.
   - **4.6.** Load-Serving Entities.
   - **4.7.** Purchasing-Selling Entities.
5. ***Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:

- **R1.1.** Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
- **R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.

R1.4. System real and reactive reserves (actual versus required).

R1.5. Capacity and energy adequacy conditions.

R1.6. Current ACE for all its Balancing Authorities.

R1.7. Current local or Transmission Loading Relief procedures in effect.

R1.8. Planned generation dispatches.

R1.9. Planned transmission or generation outages.

R1.10. Contingency events.

R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

R3. Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

R4. The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.

R5. Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

R6. The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.

R7. As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.

R8. The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

R9. Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

R10. In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

R11. The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

R12. Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)

M3. The Reliability Coordinator shall 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 it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)

M4. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.

M5. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.

M6. The Transmission Operators and Balancing Authorities shall 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 confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)

M7. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

M8. If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)

M9. If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 9)

M10. If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 10)

M11. The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11 Part 2)

M12. The Reliability Coordinator shall 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 confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.

M13. The Reliability Coordinator shall 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 confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.

M14. The Reliability Coordinator shall 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 confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

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

1.3. Data Retention

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

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

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

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.	The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-1 R1.1 through R1.10.
R1.1	The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.	N/A	N/A	N/A
R1.2	The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A

Requirement	Lower	Moderate	High	Severe
R1.3	The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.	N/A	N/A	N/A
R1.4	The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).	N/A	N/A	N/A
R1.5	The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.	N/A	N/A	N/A
R1.6	The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.	N/A	N/A	N/A
R1.7	The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.	N/A	N/A	N/A

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Requirement	Lower	Moderate	High	Severe
R1.8	The Reliability Coordinator failed to monitor planned generation dispatches.	N/A	N/A	N/A
R1.9	The Reliability Coordinator failed to monitor planned transmission or generation outages.	N/A	N/A	N/A
R1.10	The Reliability Coordinator failed to monitor contingency events.	N/A	N/A	N/A
R2	N/A	The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.	The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.

Requirement	Lower	Moderate	High	Severe
R3	N/A	N/A	The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.	The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.
R4	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.

Requirement	Lower	Moderate	High	Severe
R5	N/A	N/A	The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.	The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

Requirement	Lower	Moderate	High	Severe
R6	N/A	The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans, or the Reliability Coordinator coordinated pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in the real-time reliability analysis timeframe but failed to coordinate pending generation and transmission maintenance outages in the next-day reliability analysis timeframe.	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations, or the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.	The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.

Requirement	Lower	Moderate	High	Severe
R7	N/A	N/A	N/A	The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.
R8	N/A	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.	The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.

Requirement	Lower	Moderate	High	Severe
R9	N/A	N/A	N/A	The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Special Protection System that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.
R10	N/A	N/A	N/A	The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.

Requirement	Lower	Moderate	High	Severe
R11	N/A	N/A	N/A	The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
R12	N/A	The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	N/A	The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17 Retired M2 and M3; modified M9 and M12; retired M13 Made conforming changes to data retention Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Retired VSLs associated with R2, R3, R5, R16 and R17; Modified VSLs associated with R9 and R13, and R14	Revised
2	November 1, 2006	Approved by the Board of Trustees	
2	January 1, 2007	Effective Date	
3	October 17, 2008	Approved by the Board of Trustees	
2a/3a	November 5, 2009	Interpretation adopted by the Board of Trustees	
3	March 17, 2011	Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)	
2a/3a	April 21, 2011	Order issued by FERC approving Interpretation (approval effective	

		5/26/11)	

Appendix 1

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6:* New or degraded special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12**[1] **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other

[1] In the current version of the Standard (IRO-005-3a), this requirement is R9.

reliability entities that is needed “to perform assessments and to coordinate operations.”

The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. **Title: Reliability Coordination — Transmission Loading Relief (TLR)**
2. **Number: IRO-006-5**
3. **Purpose:** To ensure coordinated action between Interconnections when implementing Interconnection-wide transmission loading relief procedures to prevent or manage potential or actual SOL and IROL exceedances to maintain reliability of the bulk electric system.
4. **Applicability:**

   4.1. Reliability Coordinator.

   4.2. Balancing Authority.
5. ***Proposed Effective Date:** First day of the first calendar quarter following the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required; the standard becomes effective on the first day of the first calendar quarter after the date this standard is approved by the NERC Board of Trustees.

B. Requirements

R1. Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request. [*Violation Risk Factor: High*] [*Time Horizon: Real-time Operations*]

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall provide evidence (such as dated logs, voice recordings, Tag histories, and studies, in electronic or hard copy format) that, when a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure was made from another Reliability Coordinator, Balancing Authority, or Transmission Operator in that other Interconnection, it complied with the request or provided a reliability reason why it could not comply with the request (R1).

D. Compliance

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

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

- The Reliability Coordinator and Balancing Authority shall maintain evidence to show compliance with R1 for the most recent twelve calendar months plus the current month.
- If a Reliability Coordinator or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the duration specified above, whichever is longer.

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

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1				The responsible entity received a request to curtail an Interchange Transaction crossing an Interconnection boundary pursuant to an Interconnection-wide transmission loading relief procedure from a Reliability Coordinator, Balancing Authority, or Transmission Operator, but the entity neither complied with the request, nor provided a reliability reason why it could not comply with the request.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

E. Variances

None.

F. Associated Documents

None.

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	August 8, 2005	Revised Attachment 1	Revision
3	February 26, 2007	Revised Purpose and Attachment 1 related to NERC NAESB split of the TLR procedure	Revision
4	October 23, 2007	Completed NERC/NAESB split	Revision
5	TBD	Removed Attachment 1 and made into a new standard, eliminated unnecessary requirements.	Revision
5	November 4, 2010	Approved by the Board of Trustees	
5	April 21, 2011	FERC Order issued approving IRO-006-5 (approval effective June 27, 2011)	

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief

A. Introduction

1. **Title:** **Qualified Transfer Path Unscheduled Flow (USF) Relief**

2. **Number:** IRO-006-WECC-1

3. **Purpose:** Mitigation of transmission overloads due to unscheduled flow on Qualified Transfer Paths.

4. **Applicability**

   4.1. Balancing Authorities

   4.2 Reliability Coordinators

5. ***Effective Date:** The first day of the first quarter after applicable regulatory approvals.

B. Requirements

R1. Upon receiving a request of Step 4 or greater (see Attachment 1-IRO-006-WECC-1) from the Transmission Operator of a Qualified Transfer Path, the Reliability Coordinator shall approve (actively or passively) or deny that request within five minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. The Balancing Authorities shall approve curtailment requests to the schedules as submitted, implement alternative actions, or a combination there of that collectively meets the Relief Requirement. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Reliability Coordinator shall have evidence that it approved or denied the request within five minutes in accordance with R1.

M2. The Balancing Authorities shall have evidence that they provided the Relief Requirement through Contributing Schedules curtailments, alternative actions, or a combination that collectively meets the Relief Requirement as directed in R.2.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reviews conducted monthly

- Spot check audits conducted anytime with 30 days notice given to prepare

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

- Periodic audit as scheduled by the Compliance Enforcement Authority

- Investigations

- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 Compliance Monitoring Period: A Qualified Transfer Path Curtailment Event

1.2.2 The Performance-reset Period is one calendar month.

1.3. Data Retention

Reliability Coordinators and Balancing Authorities shall keep evidence for Measure M.1 through M2 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

Compliance shall be determined by a single event, per path, per calendar month (at a minimum) provided at least one event occurs in that month.

2. Violation Severity Levels of Non-Compliance for Requirement R1

2.1. **Lower:** There shall be a Lower Level of non-compliance if there is one instance during a calendar month in which the Reliability Coordinator approved (actively or passively) or denied a Step 4 or greater request greater than five minutes after receipt of notification from the Transmission Operator of a Qualified Transfer Path.

2.2. **Moderate:** Not Applicable

2.3. **High:** Not Applicable

2.4. **Severe:** Not Applicable

3. Violation Severity Levels of Non-Compliance for Requirement R2

3.1. **Lower:** There shall be a Lower Level of non-compliance if there is less than 100% Relief Requirement provided but greater than or equal to 90% Relief Requirement provided or the Relief Requirement was less than 5 MW and was not provided.

3.2. **Moderate:** There shall be a Moderate Level of non-compliance if there is less than 90% Relief Requirement provided but greater than or equal to 75% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

3.3. **High:** There shall be a High Level of non-compliance if there is less than 75% Relief Requirement provided but greater than or equal to 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

3.4. **Severe:** There shall be a Severe Level of non-compliance if there is less than 60% Relief Requirement provided and the Relief Requirement was greater than 5 MW and was not provided.

Version History – Shows Approval History and Summary of Changes in the Action Field

WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for IRO-STD-006-0	
1	February 10, 2009	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-006-WECC-1 (FERC approval is effective on May 24, 2011)	
1	May 2, 2012	Updated the requirements to R1. and R2. instead of R.1. and R1.2.	

WECC Standard IRO-006-WECC-1 – Qualified Transfer Path Unscheduled Flow Relief

Attachment 1 WECC IRO-006-WECC-1
WECC UNSCHEDULED FLOW MITIGATION
SUMMARY OF ACTIONS

Step	**Action Description**	Unscheduled Flow Accommodation across Path	**Equivalent Percent Curtailment Required in Contributing Schedule -Based on amount of Unscheduled Flow across the Qualified Transfer Path** (Transfer Distribution Factor)				
			10-14%	**15-19%**	**20-29%**	**30-49%**	**50+ %**
1	Operate controllable devices in path	NA					
2	Accommodation	50 MW or 5% of maximum transfer limit					
3	Coordinated operation of Qualified Controllable Devices	50 MW or /5% of maximum transfer limit					
4	First level curtailment	50 MW or 5% of maximum transfer limit				10%	20%
5	Second level curtailment	50 MW or 5% of maximum transfer limit			10%	15%	25%
6	Accommodation	75 MW or 6% of maximum transfer limit			10%	15%	25%
7	Third level curtailment	75 MW or 6% of maximum transfer limit		10%	15%	20%	30%
8	Accommodation	100 MW or 7% of maximum transfer limit		10%	15%	20%	30%
9	Fourth level curtailment	100 MW or 7% of maximum transfer limit	10%	15%	20%	25%	35%

A. Introduction

1. **Title: Reliability Coordinator Operational Analyses and Real-time Assessments**

2. **Number:** IRO-008-1

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring that the Bulk Electric System is assessed during the operations horizon.

4. **Applicability**

   4.1. Reliability Coordinator.

5. ***Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning)*

R2. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. *(Violation Risk Factor: Medium) (Time Horizon: Real-time Operations or Same Day Operations)*

C. Measures

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

M1. The Reliability Coordinator shall have, and make available upon request, the results of its Operational Planning Analyses.

M2. The Reliability Coordinator shall have, and make available upon request, evidence to show it conducted a Real-Time Assessment at least once every 30 minutes. This evidence could include, but is not limited to, dated computer log showing times the assessment was conducted, dated checklists, or other evidence.

M3. The Reliability Coordinator shall have and make available upon request, evidence to confirm that it shared the results of its Operational Planning Analyses or Real-Time Assessments with those entities expected to take actions based on that information. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated transcripts of voice records, dated facsimiles, or other evidence.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

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

The Reliability Coordinator shall retain evidence for Requirement R1, Measure M1 and Requirement R2, Measure M2 for a rolling 30 days. The Reliability

Coordinator shall keep evidence for Requirement R3, Measure M3 for a rolling three months.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1	Performed an Operational Planning Analysis that covers all aspects of the requirement for all except one of 30 days. (R1)	Performed an Operational Planning Analysis that covers all aspects of the requirement for all except two of 30 days. (R1)	Performed an Operational Planning Analysis that covers all aspects of the requirement for all except three of 30 days. (R1)	Missed performing an Operational Planning Analysis that covers all aspects of the requirement for four or more of 30 days. (R1)
R2	For any sample 24 hour period within the 30 day retention period, a Real-time Assessment was not conducted for one 30-minute period. within that 24-hour period (R2)	For any sample 24 hour period within the 30 day retention period, Real-time Assessments were not conducted for two 30-minute periods within that 24-hour period (R2)	For any sample 24 hour period within the 30 day retention period, Real-time Assessments were not conducted for three 30-minute periods within that 24-hour period (R2)	For any sample 24 hour period within the 30 day retention period, Real-time Assessments were not conducted for more than three 30-minute periods within that 24-hour period (R2)
R3		Shared the results with some but not all of the entities that were required to take action (R3)		Did not share the results of its analyses or assessments with any of the entities that were required to take action (R3).

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-008-1 (approval effective 5/23/11)	

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

A. Introduction

1. **Title:** **Reliability Coordinator Actions to Operate Within IROLs**
2. **Number:** IRO-009-1
3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).
4. **Applicability:**

    4.1. Reliability Coordinator.

5. ***Proposed Effective Date:**

    In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

    In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning or Same Day Operations)*

R2. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's T_v. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning or Same Day Operations)*

R3. When an assessment of actual or expected system conditions predicts that an IROL in its Reliability Coordinator Area will be exceeded, the Reliability Coordinator shall implement one or more Operating Processes, Procedures or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirements R1) to prevent exceeding that IROL. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

R4. When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's T_v. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

R5. If unanimity cannot be reached on the value for an IROL or its T_v, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration. *(Violation Risk Factor: High) (Time Horizon: Real-time Operations)*

C. Measures

M1. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it has Operating Processes, Procedures, or Plans to address both preventing and mitigating instances of exceeding IROLs in accordance with Requirement R1 and Requirement R2. This evidence shall include a list of any IROLs (and each associated T_v) identified in advance, along with one or more dated Operating Processes, Procedures, or Plans that that will be used.

M2. Each Reliability Coordinator shall have, and make available upon request, evidence to confirm that it acted or directed others to act in accordance with Requirement R3 and Requirement R4. This evidence could include, but is not limited to, Operating Processes, Procedures, or Plans from Requirement R1, dated operating logs, dated voice recordings, dated transcripts of voice recordings, or other evidence.

M3. For a situation where Reliability Coordinators disagree on the value of an IROL or its T_v the Reliability Coordinator shall have, and make available upon request, evidence to confirm that it used the most conservative of the values under consideration, without delay. Such evidence could include, but is not limited to, dated computer printouts, dated operator logs, dated voice recordings, dated transcripts of voice recordings, or other equivalent evidence. (R5)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Exception Reporting

1.4. Data Retention

The 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 Reliability Coordinator shall retain evidence of Requirement R1, Requirement R2, and Measure M1, for a rolling 12 months.
>
> The Reliability Coordinator shall retain evidence of Requirement R3, Requirement R4, Requirement R5, Measure M2, and Measure M3 for a rolling 12 months.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records, and all IROL Violation Reports submitted since the last audit.

1.5. Additional Compliance Information

Exception Reporting: For each instance of exceeding an IROL for time greater than IROL T_v, the Reliability Coordinator shall submit an IROL Violation Report to its Compliance Enforcement Authority within 30 days of the initiation of the event.

2. Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1				An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL. (R1)
R2				An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's T_v. (R2)
R3				An assessment of actual or expected system conditions predicted that an IROL in the Reliability Coordinator's Area would be exceeded, but

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Requirement	Lower	Moderate	High	Severe
				no Operating Processes, Procedures, or Plans were implemented. (R3)
R4			Actual system conditions showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and there was a delay of five minutes or more before acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding that IROL, however the IROL was mitigated within the IROL T_v. (R4)	Actual system conditions showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and that IROL was not resolved within the IROL's T_v. (R4)
R5	Not applicable.	Not applicable.	Not applicable.	There was a disagreement on the value of the IROL or its T_v and the most conservative limit under consideration was not used. (R5)

E. Regional Variances

None

F. Associated Documents

IROL Violation Report

Version History

Version	Date	Action	Change Tracking
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving IRO-009-1 (approval effective 5/23/11)	

A. Introduction

1. **Title:** **Reliability Coordinator Data Specification and Collection**
2. **Number:** IRO-010-1a
3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring the Reliability Coordinator has the data it needs to 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.** Interchange Authority.
   - **4.6.** Load-Serving Entity.
   - **4.7.** Transmission Operator.
   - **4.8.** Transmission Owner.
5. ***Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.

R1.2. Mutually agreeable format.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses).

R1.4. Process for data provision when automated Real-Time system operating data is unavailable.

R2. The Reliability Coordinator shall distribute its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. *(Violation Risk Factor: Low) (Time Horizon: Operations Planning)*

R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship. *(Violation Risk Factor: Medium) (Time Horizon: Operations Planning; Same-day Operations; Real-time Operations)*

C. Measures

M1. The Reliability Coordinator shall have, and make available upon request, a documented data specification that contains all elements identified in Requirement R1.

M2. The Reliability Coordinator shall have, and make available upon request, evidence that it distributed its data specification to entities that have Facilities monitored by the Reliability Coordinator and to entities that provide Facility status to the Reliability Coordinator. This evidence could include, but is not limited to, dated paper or electronic notice used to distribute its data specification showing recipient, and data or information requested or other equivalent evidence. (R2)

M3. The Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner shall each have, and make available upon request, evidence to confirm that it provided data and information, as specified in Requirement R3. This evidence could include, but is not limited to, dated operator logs, dated voice recordings, dated computer printouts, dated SCADA data, or other equivalent evidence.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

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

The Reliability Coordinator shall retain its current, in force data specification for Requirement R1, Measure M1.

The Reliability Coordinator shall keep evidence of its most recent distribution of its data specification and evidence to show the data supplied in response to that specification for Requirement R2, Measure M2 and Requirement R3 Measure M3.

For data that is requested in accordance with Requirement R2, the Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Reliability Coordinator, Transmission Operator and Transmission Owner shall keep evidence used to show compliance with Requirement R3 Measure M3 for the Reliability Coordinator's most recent data specification for a rolling 90 calendar days.

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

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels

Requirement	Lower	Moderate	High	Severe
R1	Data specification is complete with the following exception: Missing the mutually agreeable format. (R1.2)	Data specification is complete with the following exception – no process for data provision when automated Real-Time system operating data is unavailable. (R1.4)	Data specification incomplete (missing either the list of required data (R1.1), or the timeframe for providing data. (R1.3)	No data specification (R1)
R2	Distributed its data specification to greater than or equal to 95% but less than 100% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status.	Distributed its data specification to greater than or equal to 85% but less than 95% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)	Distributed its data specification to greater than or equal to 75% - but less then 85% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)	Data specification distributed to less than 75% of the entities that have Facilities monitored by the Reliability Coordinator and the entities that provide the Reliability Coordinator with Facility status. (R2)
R3	Provided greater than or equal to 95% but less then 100% of the data and information as specified. (R3)	Provided greater than or equal to 85% but less than 95% of the data and information as specified. (R3)	Provided greater than or equal to 75% but less then 85% of the data and information as specified. (R3)	Provided less than 75% of the data and information as specified. (R3)

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

E. Regional Variances

None

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1.2 and R3

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)	

Appendix 1

Interpretation of Requirements R1.2 and R3

Text of Requirements R1.2 and R3

R1. **The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following:**

R1.1. **List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments.**

R1.2. **Mutually agreeable format.**

R1.3. **Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses).**

R1.4. **Process for data provision when automated Real-Time system operating data is unavailable.**

R3. **Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.**

Question 1

Does the phrase, "as specified" in Requirement R3 reference the documented data and information specification in IRO-010-1 Requirement R1, or is the data and information in Requirement R3 "any" data and information that the Reliability Coordinator might request?

Response: The data to be supplied in Requirement R3 applies to the documented specification for data and information referenced in Requirement R1.

Question 2

Is the intent of Requirement R3 to have each responsible entity provide its own data and information to its Reliability Coordinator, or is the intent to have responsible entities provide aggregated data (collected and compiled from other entities at the direction of the Reliability Coordinator) to the Reliability Coordinator?

Response: The intent of Requirement R3 is for each responsible entity to ensure that its data and

information (as stated in the documented specification in Requirement R1) are provided to the Reliability Coordinator.

Another entity may provide that data or information to the Reliability Coordinator on behalf of the responsible entity, but the responsibility remains with the responsible entity. There is neither intent nor obligation for any entity to compile information from other entities and provide it to the Reliability Coordinator.

Question 3

Under Requirement R1.2, what actions (on the part of the Reliability Coordinator) are expected to support the "mutually acceptable format" for submission of data and information?

Response: Requirement R1.2 mandates that the parties will reach a mutual agreement with respect to the format of the data and information. If the parties can not mutually agree on the format, it is expected that they will negotiate to reach agreement or enter into dispute resolution to resolve the disagreement.

Standard MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

A. Introduction

1. **Title:** **Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-1

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. ***(Proposed) Effective Date:** The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption.

B. Requirements

R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Standard MOD-021-1 — Accounting Methodology for Effects of DSM in Forecasts

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

None specified.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels (no changes)

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	R1. – comma inserted after Load-Serving Entity	
0.1	December 10, 2009	Approved by FERC — Added effective date	Update
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 1300.	Revised.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

A. Introduction

1. **Title:** **Reliability Coordination — Staffing**
2. **Number:** PER-004-2
3. **Purpose:**

   Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.

4. **Applicability**

   4.1. Reliability Coordinators.

5. ***Effective Date:**

   - Retire Requirement 2 when PER-005-1 Requirement 3 becomes effective.
   - Retire Requirements 3 and 4 when PER-005-1 Requirements 1 and 2 become effective.

B. Requirements

R1. Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.

R2. Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.

C. Measures

None

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The British Columbia Utilities Commission

   1.2. Compliance Monitoring and Reset Time Frame

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

   - Self-certification (Conducted annually with submission according to schedule.)
   - Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

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

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

1.3. Data Retention

Each Reliability Coordinator shall keep evidence of compliance for the previous two calendar years plus the current year.

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Reliability Coordinator (Replaced with VSLs)

2.1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

2		Retire R2 and M1 when PER-005-1 Requirement 3 becomes effective. Retire R3, R4 and M2 when PER-005 R1 and R2 become effective.	Revised

Standard PER-005-1 — System Personnel Training

A. Introduction

1. **Title:** **System Personnel Training**
2. **Number:** PER-005-1
3. **Purpose:** To ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System (BES) are competent to perform those reliability-related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator.

   4.1.2 Balancing Authority.

   4.1.3 Transmission Operator.
5. ***Proposed Effective Date for Regulatory Approvals:**

   5.1. In those jurisdictions where regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R1 and Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   5.2. In those jurisdictions where regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after Board of Trustees adoption.

   5.3. In those jurisdictions where regulatory approval is required Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after Board of Trustees adoption.

B. Requirements

R1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

R1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators.

R1.1.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to identify new or modified tasks for inclusion in training.

R1.2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1.

R1.3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2.

R1.4. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.

R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

R2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.

R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.

C. Measures

M1. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence of using a systematic approach to training to establish and implement a training program, as specified in R1.

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its company-specific reliability-related task list, with the date of the last review and/or revision, as specified in R1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its learning objectives and training materials, as specified in R1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered and the dates of delivery to show that it delivered the training, as specified in R1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an annual training program evaluation, as specified in R1.4

M2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection evidence to show that it verified that each of its System Operators is capable of performing each assigned task identified in R1.1, as specified in R2. This evidence can be documents such as training records showing successful completion of tasks with the employee name and date; supervisor check sheets showing the employee name, date, and task completed; or the results of learning assessments.

M3. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection training records that provide evidence that each System Operator has obtained 32 hours of emergency operations training, as specified in R3.

M3.1 Each Reliability Coordinator, Balancing Authority and Transmission Operator shall have available for inspection training records that provide evidence that each System Operator received emergency operations training using simulation technology, as specified in R3.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each Reliability Coordinator, Balancing Authority and Transmission Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is the greatest, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority and Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.5. Additional Compliance Information

None.

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	None	The responsible entity failed to provide evidence that it updated its company-specific reliability-related task list to identify new or modified tasks each calendar year (R1.1.1) OR The responsible entity failed to provide evidence of evaluating its training program to identify needed changes to its training program(s). (R1.4)	The responsible entity failed to design and develop learning objectives and training materials based on the BES company specific reliability related tasks. (R1.2)	The responsible entity failed to prepare a company-specific reliability-related task list (R1.1) OR The responsible entity failed to deliver training based on the BES company specific reliability related tasks. (R1.3)
R2	None	The responsible entity verified at least 90% but less than 100% of its System Operators' capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)	The responsible entity verified at least 70% but less than 90% of its System Operators' capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks (R2) OR The responsible entity failed to verify its system operator's capabilities to perform each new or modified task within six months of making a modification to its BES company-specific reliability-related task list. (R2.1)	The responsible entity verified less than 70% of its System Operators' capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)
R3	None	The responsible entity provided at least 32 hours of emergency operations	The responsible entity provided at least 32 hours of emergency operations	The responsible entity provided 32 hours of emergency operations training to less

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

Standard PER-005-1 — System Personnel Training

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
		training to at least 90% but less than 100% of their System Operators. (R3)	training to at least 70% but less than 90% of its System Operators. (R3)	than 70% of its System Operators (R3) OR The responsible entity did not include simulation technology replicating the operational behavior of the BES in its emergency operations training. (R3.1)

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking

***Mandatory BC effective date for R1 and R2: January 15, 2015 per BCUC Order R-1-13**
***Mandatory BC effective date for R3: July 15, 2014 per BCUC Order R-1-13**
***Mandatory BC effective date for R3.1: January 15, 2016 per BCUC Order R-1-13**

A. Introduction

1. **Title: Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-1a

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. ***Effective Date:** To be determined

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization’s procedures developed for PRC-003 R1.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. **Level 1:** Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. **Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. **Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. **Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
1	February 7, 2006	Adopted by the Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	

Appendix 1

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

A. Introduction

1. Title: Protection System and Remedial Action Scheme Misoperation

2. Number: PRC-004-WECC-1

3. Purpose: Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. Applicability

4.1. Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf and "Major WECC Remedial Action Schemes (RAS)" provided at http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf.

4.2. Generator Owners that own RAS listed in the Table titled "Major WECC Remedial Action Schemes (RAS)" provided at http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf.

4.3. Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled "Major WECC Transfer Paths in the Bulk Electric System" provided at http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf and "Major WECC Remedial Action Schemes (RAS)" provided at http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf.

5. *Effective Date: On the first day of the second quarter following applicable regulatory approval.

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled "Major WECC Transfer Paths in the Bulk Electric System" and "Major WECC Remedial Action Schemes (RAS)."

R.1. System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R1.1. System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.

R1.2. System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.

R.2. Transmission Owners and Generator Owners shall perform the following actions for each

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the Transmission Owner or Generator Owner identifies the Misoperation:

R2.1. If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2. If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.2.1. Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.

R2.2.2. The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.

R2.3. If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R2.3.1. When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.

R2.3.2. When FERAS is not available, then

2.3.2.1. The Generator Owners shall adjust generation to a reliable operating level, or

2.3.2.2. Transmission Operators shall adjust the SOL and operate the facilities within established limits.

R2.4. If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.

R2.4.1. Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or

R2.4.2. Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R.3. Transmission Owners and Generation Owners shall submit Misoperation incident reports to WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

R3.1. Identification of a Misoperation of a Protection System and/or RAS,

R3.2. Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

M1. Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.

M1.1 Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.

M1.2 Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.

M2. Transmission Owners and Generation Owners shall have evidence for the following.

M2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2 Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.

M2.2.1 Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.

M2.2.2 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.

M2.3 The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.

M2.3.1 The Transmission Owner shall have evidence that it removed the associated Element from service.

M2.3.2 The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.

M2.4 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.

M2.4.1 Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

M2.4.2 Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

M3. Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

M3.1 Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

M3.2 Completion of repair or replacement of Protection System and/or RAS that misoperated.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority

- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 The Performance-reset Period is one calendar month.

1.3 Data Retention

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

Lower	Moderate	High	Severe
System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.

R2.1 and R2.2.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.3

Lower	Moderate	High	Severe
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.2.2 and R2.4

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.

R3.1

Lower	Moderate	High	Severe

The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

R3.2

Lower	**Moderate**	**High**	**Severe**
The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1	
1	April 21, 2011	FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011)	

A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**

2. **Number:** PRC-005-1a

3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Generator Owner.

   4.3. Distribution Provider that owns a transmission Protection System.

5. ***Effective Date:** To be determined

B. Requirements

R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:

R1.1. Maintenance and testing intervals and their basis.

R1.2. Summary of maintenance and testing procedures.

R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:

R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.

R2.2. Date each Protection System device was last tested/maintained.

C. Measures

M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.

M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.

2.2. Level 2: Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.

2.3. Level 3: Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)." 2. Added "periods" to items where appropriate. 3. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/05
1	February 7, 2006	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC's Order is effective as of September 26, 2011)	

Appendix 1

Requirement Number and Text of Requirement
R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include: **R1.1.** Maintenance and testing intervals and their basis. **R1.2.** Summary of maintenance and testing procedures. **R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include: **R2.1** Evidence Protection System devices were maintained and tested within the defined intervals. **R2.2** Date each Protection System device was last tested/maintained.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-005-1 Requirements R1 and R2 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

A. Introduction

1. **Title:** **Reliability Responsibilities and Authorities**

2. **Number:** TOP-001-1a

   Purpose: To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

3. **Applicability**

   3.1. Balancing Authorities

   3.2. Transmission Operators

   3.3. Generator Operators

   3.4. Distribution Providers

   3.5. Load Serving Entities

4. ***Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall 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 other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall 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 other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each 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 other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each 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 other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

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

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

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

3.4.1 Does not have the documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1a	May 12, 2010	Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010	Interpretation
1a	September 15, 2011	FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)	Interpretation

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

Appendix 1

Requirement Number and Text of Requirement
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.
Question
For Requirement R8 is the Balancing Authority responsibility to immediately take corrective action to restore Real Power Balance and is the TOP responsibility to immediately take corrective action to restore Reactive Power Balance?
Response
The answer to both questions is yes. According to the NERC *Glossary of Terms Used in Reliability Standards*, the Transmission Operator is responsible for the reliability of its "local" transmission system, and operates or directs the operations of the transmission facilities. Similarly, the Balancing Authority is responsible for maintaining load-interchange-generation balance, i.e., real power balance. In the context of this requirement, the Transmission Operator is the functional entity that balances reactive power. Reactive power balancing can be accomplished by issuing instructions to the Balancing Authority or Generator Operators to alter reactive power injection. Based on NERC Reliability Standard BAL-005-1b Requirement R6, the Transmission Operator has no requirement to compute an Area Control Error (ACE) signal or to balance real power. Based on NERC Reliability Standard VAR-001-1 Requirement R8, the Balancing Authority is not required to resolve reactive power balance issues. According to TOP-001-1 Requirement R3, the Balancing Authority is only required to comply with Transmission Operator or Reliability Coordinator instructions to change injections of reactive power.

Standard TOP-002-2b — Normal Operations Planning

A. Introduction

1. **Title:** **Normal Operations Planning**
2. **Number:** TOP-002-2b
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
   - **4.3.** Generator Operator.
   - **4.4.** Load Serving Entity.
   - **4.5.** Transmission Service Provider.
5. ***Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

Standard TOP-002-2b — Normal Operations Planning

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

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

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

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

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

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

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

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Standard TOP-002-2b — Normal Operations Planning

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation
2b	November 4, 2010	Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees	
2b	October 20, 2011	FERC Order issued approving the Interpretation of R10 (FERC’s Order became effective on October 20, 2011)	

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

Standard TOP-002-2b — Normal Operations Planning

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard

provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

Appendix 2

Requirement Number and Text of Requirement:

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Clarification needed:

Requirement 10 is proposed to be eliminated in Project 2007-03 because it is redundant with TOP-004-0 R1, which only applies to TOP not to BA. However, that will not be effective for more than two years. In the meantime, in Requirement 10 is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Project 2009-27: Response to Request for an Interpretation of TOP-002-2a, Requirement R10, for Florida Municipal Power Pool

The following interpretation of TOP-002-2a — Normal Operations Planning, Requirement R10, was developed by the Real-time Operations Standard Drafting Team.

Requirement Number and Text of Requirement

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

Question

In Requirement 10, is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?

Standard TOP-002-2b — Normal Operations Planning

Response
Yes. As stated in the NERC *Glossary of Terms used in Reliability Standards*, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows (MW, MVAR or Ampere) or voltage. Therefore, the Balancing Authority must follow the directions of the Transmission Operator to meet all SOLs and IROLs.

Standard-TOP-003-1 — Planned Outage Coordination

A. Introduction

1. **Title:** **Planned Outage Coordination**
2. **Number:** TOP-003-1
3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
4. **Applicability**
   - **4.1.** Generator Operators.
   - **4.2.** Transmission Operators.
   - **4.3.** Balancing Authorities.
   - **4.4.** Reliability Coordinators.
5. ***Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers,

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

The Compliance Monitor shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Compliance Monitor an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Compliance Monitor to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by the Compliance Monitor.

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

(TBD)

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
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)	

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Standard TOP-005-1.1a — Operational Reliability Information

A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-1.1a
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Reliability Coordinators.
   - **4.4.** Purchasing Selling Entities.
5. ***Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.

R1.1. Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.

R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R4. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

***Mandatory BC effective date: Not applicable per BCUC Order R-1-13**

C. Measures

M1. Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R4 is providing the requesting entities with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R4 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity's list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

***Mandatory BC effective date: Not applicable per BCUC Order R-1-13**

Standard TOP-005-1.1a — Operational Reliability Information

1	November 6, 2007	Revised D.2.1 and D.2.4 reference "Requirements R1 to R5" "to Requirements R1 to R4."	Errata
1.1	October 29, 2008	BOT adopted errata changes; updated version number to "1.1"	Errata
1.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1.1a	November 5, 2009	Added Appendix 2 – Interpretation of R3 approved by BOT on November 5, 2009	Interpretation
1.1a	April 21, 2011	FERC Order issued approving Interpretation (approval effective May 26, 2011)	Interpretation

***Mandatory BC effective date: Not applicable per BCUC Order R-1-13**

Attachment 1 — TOP-005-1.1

Electric System Reliability Data

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

Appendix 2

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3 Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6:* New or degraded special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12** **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a "performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations."

Standard TOP-005-1.1a — Operational Reliability Information

The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

Standard TOP-005-2a — Operational Reliability Information

A. Introduction

1. **Title:** **Operational Reliability Information**

2. **Number:** TOP-005-2a

3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Purchasing Selling Entities.

5. ***Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	New
2	March 17, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	
2a	April 21, 2011	Added FERC approved Interpretation	

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

- **2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
- **2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
- **2.3.** Forecast peak demand for current day and next day.
- **2.4.** Forecast changes in equipment status.
- **2.5.** New facilities in place.
- **2.6.** New or degraded special protection systems.
- **2.7.** Emergency operating procedures in effect.
- **2.8.** Severe weather, fire, or earthquake.
- **2.9.** Multi-site sabotage.

Appendix 2

Requirement Number and Text of Requirement
TOP-005-1 Requirement R3[1] Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability. *The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6:* New or <u>degraded</u> special protection systems. *[Underline added for emphasis.]* **IRO-005-1 Requirement R12** **R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any <u>degradation</u> or potential failure to operate as expected. *[Underline added for emphasis.]* **PRC-012-0 Requirements R1 and R1.3** **R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include: **R1.3.** Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
Background Information for Interpretation
The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a "responsibility mandate." Requirement R1 establishes who is responsible for the obligation to provide operating data "required" by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a

[1] In the current version of the Standard (TOP-005-2a), this requirement is R2.

"performance mandate." Requirement R3 defines the obligation to provide data "requested" by other reliability entities that is needed "to perform assessments and to coordinate operations."

The Attachment to TOP-005-1 is provided as a guideline of what "can be shared." The Attachment is not an obligation of "what must be shared." Enforceable NERC Requirements must be explicitly contained within a given Standard's approved requirements. In this case, the standard only requires data "upon request." If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined "degraded" state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator's obligation to be aware of conditions that may have a "significant" impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term "degraded."

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed. If the loss of a communication channel will result in the failure of an SPS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure

requires the submittal of a Standards Authorization Request.

Standard TOP-006-2 — Monitoring System Conditions

A. Introduction

1. **Title:** **Monitoring System Conditions**
2. **Number:** TOP-006-2
3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Generator Operators.
   - **4.4.** Reliability Coordinators.
5. ***Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Standard TOP-006-2 — Monitoring System Conditions

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring and Reset Time Frame

Standard TOP-006-2 — Monitoring System Conditions

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

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

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

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

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

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

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

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

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.
R1.1	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
R1.2	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
R2	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

Standard TOP-006-2 — Monitoring System Conditions

R#	Lower	Moderate	High	Severe
R3	The responsible entity failed to provide any of the appropriate technical information concerning protective relays to their operating personnel.	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information concerning protective relays to their operating personnel.
R4	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R5	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.
R6	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R7	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.

Standard TOP-006-2 — Monitoring System Conditions

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Modified R4 Modified M4 Modified Data Retention for M4 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 17, 2011	Order issued by FERC approving TOP-006-2 (approval effective 5/23/11)	

WECC Standard TOP-007-WECC-1 — System Operating Limits

A. Introduction

1. **Title:** **System Operating Limits**

2. **Number:** TOP-007-WECC-1

3. **Purpose:** When actual flows on Major WECC Transfer Paths exceed System Operating Limits (SOL), their associated schedules and actual flows are not exceeded for longer than a specified time.

4. **Applicability**

   4.1. Transmission Operators for the transmission paths in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" provided at:

   http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf

5. ***Effective Date:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. When the actual power flow exceeds an SOL for a Transmission path, the Transmission Operators shall take immediate action to reduce the actual power flow across the path such that at no time shall the power flow for the Transmission path exceed the SOL for more than 30 minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R2. The Transmission Operator shall not have the Net Scheduled Interchange for power flow over an interconnection or Transmission path above the path's SOL when the Transmission Operator implements its real-time schedules for the next hour. For paths internal to a Transmission Operator Area that are not scheduled, this requirement does not apply. *[Violation Risk Factor: Low] [Time Horizon: Real-time Operations]*

R2.1. If the path SOL decreases within 20 minutes before the start of the hour, the Transmission Operator shall adjust the Net Scheduled Interchange within 30 minutes to the new SOL value. Net Scheduled Interchange exceeding the new SOL during this 30-minute period will not be a violation of R2.

C. Measures

M1. Evidence that actual power flow has not exceeded the SOL for the specified time limit in R1.

M2. Evidence that Net Scheduled Interchange has not exceeded the SOL when the Transmission Operator implements real-time schedules as required by R2.

M2.1. Evidence that Net Scheduled Interchange was at or below the new SOL within 30-minutes of when the SOL decreased.

D. Compliance

1. Compliance Monitoring Process

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2 **Compliance Monitoring Period**

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Self-report for each incident within three-business day

- Self-report quarterly

- Spot check audits conducted anytime with 30 days notice given to prepare

- Periodic audit as scheduled by the Compliance Enforcement Authority

- Investigations

- Other methods as provided for in the Compliance Monitoring Enforcement Program

Reset Period: One calendar month.

1.3 Data Retention

The Transmission Operators shall keep evidence for Measure M.1 through M2 for three years plus current, or since the last audit, whichever is longer.

1.4. Additional Compliance Information

2. Violation Severity Levels

For Requirement R1:

2.1. Lower: There shall be a Lower Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.2. Moderate: There shall be a Moderate Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.3. High: There shall be a High Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

2.4. Severe: There shall be a Severe Level of non-compliance for Transmission Operators as set forth in the table in Attachment 1– TOP-007-WECC-1.

For Requirement R2:

2.1. Lower: There shall be a Lower Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above the path's SOL but is less than or equal to 105% of the path's SOL.

2.2. Moderate: There shall be a Moderate Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above 105% of the path's SOL but less than or equal to 110% of the path's SOL.

2.3. High: There shall be a High Level of non-compliance for Transmission Operators when the net schedule for power flow over an interconnection or Transmission path is above 110% of the path's SOL.

2.4 Severe: None

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for TOP-STD-007-0	
1	April 21, 2011	Order issued by FERC approving TOP-007-WECC-1 (approval effective June 27, 2011)	

Attachment 1 — TOP-007-WECC-1

Violation Severity Level Table

Percentage by which SOL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes	Limit exceeded for more than 35 minutes, up to 40 minutes	Limit exceeded for more than 40 minutes, up to 45 minutes	Limit exceeded for more than 45 minutes
greater than 0%, up to and including 5%	Lower	Moderate	Moderate	High
greater than 5%, up to and including 10%	Moderate	Moderate	High	High
greater than 10%, up to and including 15%	Moderate	High	High	Severe
greater than 15%, up to and including 20%	High	High	Severe	Severe
greater than 20%, up to and including 25%	High	Severe	Severe	Severe
greater than 25%	Severe	Severe	Severe	Severe

∗ Measured after 30 continuous minutes of actual flows in excess of SOL.

Standard TPL-002-0b — System Performance Following Loss of a Single BES Element

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-0b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. *Effective Date: Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12	Revised

***Mandatory BC effective date: January 15, 2013 per BCUC Order R-1-13**

		and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation

Standard TPL-002-0b — System Performance Following Loss of a Single BES Element

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

Standard TPL-002-0b — System Performance Following Loss of a Single BES Element

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible *generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.*

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standard TPL-002-0b — System Performance Following Loss of a Single BES Element

Appendix 2

Requirement Number and Text of Requirement
R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
Background Information for Interpretation
Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations: 1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)." 2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)." 3. "Include the effects of existing and planned protection systems, including any backup or redundant systems." *Category B of Table 1 (single Contingencies) specifies:* Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault. Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line *Note e specifies*: e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay. The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."
Conclusion
TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements

expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard VAR-001-2 — Voltage and Reactive Control

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-2
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Purchasing-Selling Entities.
   - **4.3.** Load Serving Entities.
5. ***(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load – within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

- **R3.1.** Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.
- **R3.2.** For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule [1] at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

Standard VAR-001-2 — Voltage and Reactive Control

R5. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.

R6. The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.

R6.1. When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

R7. The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load– to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

M1. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.

M2. The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

M3. The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.

M4. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

***Mandatory BC effective date: July 15, 2013 per BCUC Order R-1-13**

1	August 2, 2006	BOT Adoption	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised.

WECC Standard VAR-002-WECC-1 — Automatic Voltage Regulators

A. Introduction

1. Title: **Automatic Voltage Regulators (AVR)**

2. Number: VAR-002-WECC-1

3. Purpose: To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage.

4. Applicability

4.1. Generator Operators

4.2. Transmission Operators that operate synchronous condensers

4.3. This VAR-002-WECC-1 Standard only applies to synchronous generators and synchronous condensers that are connected to the Bulk Electric System.

5. *Effective Date: On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall have AVR in service and in automatic voltage control mode 98% of all operating hours for synchronous generators or synchronous condensers. Generator Operators and Transmission Operators may exclude hours for R1.1 through R1.10 to achieve the 98% requirement. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R1.1. The synchronous generator or synchronous condenser operates for less than five percent of all hours during any calendar quarter.

R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.

R1.3. AVR exhibits instability due to abnormal system configuration.

R1.4. Due to component failure, the AVR may be out of service up to 60 consecutive days for repair per incident.

R1.5. Due to a component failure, the AVR may be out of service up to one year provided the Generator Operator or Transmission Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.

R1.6. Due to a component failure, the AVR may be out of service up to 24 months provided the Generator Operator or Transmission Operator submits documentation identifying the need for time for excitation system replacement (replace the AVR, limiters, and controls but not necessarily the power source and power bridge) and to schedule an outage.

R1.7. The synchronous generator or synchronous condenser has not achieved Commercial Operation.

R1.8. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the AVR is unavailable for service.

***Mandatory BC effective date: January 15, 2014 per BCUC Order R-1-13**

R1.9. The Reliability Coordinator directs Transmission Operator to operate the synchronous condenser, and the AVR is unavailable for service.

R1.10. If AVR exhibits instability due to operation of a Load Tap Changer (LTC) transformer in the area, the Transmission Operator may authorize the Generator Operator to operate the excitation system in modes other than automatic voltage control until the system configuration changes.

R2. Generator Operators and Transmission Operators shall have documentation identifying the number of hours excluded for each requirement in R1.1 through R1.10. *[Violation Risk Factor: Low] [Time Horizon: Operations Assessment]*

C. Measures

M1. Generator Operators and Transmission Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator and synchronous condenser of the following:

M1.1 The actual number of hours the synchronous generator or synchronous condenser was on line.

M1.2 The actual number of hours the AVR was out of service.

M1.3 The AVR in service percentage.

M1.4 If excluding AVR out of service hours as allowed in R1.1 through R1.10, provide:

M1.4.1 The number of hours excluded, and

M1.4.2 The adjusted AVR in-service percentage.

M2. If excluding hours for R1.1 through R1.10, provide the date of the outage, the number of hours out of service, and supporting documentation for each requirement that applies.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations

***Mandatory BC effective date: January 15, 2014 per BCUC Order R-1-13**

- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators and Transmission Operators shall keep evidence for Measures M1 and M2 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.9 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.4 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the in-service percentages, do not include the time the AVR is out of service due to R1.1 through R1.10.

1.4.4 The standard shall be applied on a machine-by-machine basis (a Generator Operator or Transmission Operator can be subject to a separate sanction for each non-compliant synchronous generator and synchronous condenser).

2. Violation Severity Levels for R1

2.1. Lower: There shall be a Lower Level of non-compliance if the following condition exists:

2.1.1. AVR is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.2. Moderate: There shall be a Moderate Level of non-compliance if the following condition exists:

2.2.1. AVR is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.3. High: There shall be a High Level of non-compliance if the following condition exists:

2.3.1. AVR is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

2.4. Severe: There shall be a Severe Level of non-compliance if the following condition exists:

2.4.1. AVR is in service less than 70% of all hours during which the synchronous generating unit or synchronous condenser is on line for each calendar quarter.

***Mandatory BC effective date: January 15, 2014 per BCUC Order R-1-13**

3. Violation Severity Levels for R2

3.1. Lower: There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.10.

3.2. Moderate: There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.10.

3.3. High: Not Applicable

3.4. Severe: Not Applicable

E. Regional Differences

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002a-1	
1	April 21, 2011	FERC Order issued approving VAR-002-WECC-1 (approval effective June 27, 2011)	

WECC Standard VAR-501-WECC-1 — Power System Stabilizer

A. Introduction

1. **Title:** **Power System Stabilizer (PSS)**
2. **Number:** VAR-501-WECC-1
3. **Purpose:** To ensure that Power System Stabilizers (PSS) on synchronous generators shall be kept in service.
4. **Applicability**

   4.1. Generator Operators
5. ***Effective Date:** On the first day of the first quarter, after applicable regulatory approval.

B. Requirements

R1. Generator Operators shall have PSS in service 98% of all operating hours for synchronous generators equipped with PSS. Generator Operators may exclude hours for R1.1 through R1.12 to achieve the 98% requirement. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

R1.1. The synchronous generator operates for less than five percent of all hours during any calendar quarter.

R1.2. Performing maintenance and testing up to a maximum of seven calendar days per calendar quarter.

R1.3. PSS exhibits instability due to abnormal system configuration.

R1.4. Unit is operating in the synchronous condenser mode (very near zero real power level).

R1.5. Unit is generating less power than its design limit for effective PSS operation.

R1.6. Unit is passing through a range of output that is a known “rough zone” (range in which a hydro unit is experiencing excessive vibration).

R1.7. The generator AVR is not in service.

R1.8. Due to component failure, the PSS may be out of service up to 60 consecutive days for repair per incident.

R1.9. Due to a component failure, the PSS may be out of service up to one year provided the Generator Operator submits documentation identifying the need for time to obtain replacement parts and if required to schedule an outage.

R1.10. Due to a component failure, the PSS may be out of service up to 24 months provided the Generator Operator submits documentation identifying the need for time for PSS replacement and to schedule an outage.

R1.11. The synchronous generator has not achieved Commercial Operation.

R1.12. The Transmission Operator directs the Generator Operator to operate the synchronous generator, and the PSS is unavailable for service.

R2. Generator Operators shall have documentation identifying the number of hours

***Mandatory BC effective date: April 15, 2013 per BCUC Order R-1-13**

excluded for each requirement in R1.1 through R1.12. *[Violation Risk Factor: Low] [Time Horizon: Operations Assessment]*

C. Measures

M1. Generators Operators shall provide quarterly reports to the compliance monitor and have evidence for each synchronous generator of the following:

M1.1 The number of hours the synchronous generator was on line.

M1.2 The number of hours the PSS was out of service with generator on line.

M1.3 The PSS in service percentage

M1.4 If excluding PSS out of service hours as allowed in R1.1 through R1.12, provide:

M1.4.1 The number of hours excluded, and

M1.4.2 The adjusted PSS in-service percentage.

M2. If excluding hours for R1.1 through R1.12, provide:

M2.1 The date of the outage

M2.2 Supporting documentation for each requirement that applies

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

The British Columbia Utilities Commission

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

The Reset Time Frame shall be a calendar quarter.

1.3 Data Retention

The Generator Operators shall keep evidence for Measures M1 and M2 for three years plus current year, or since the last audit, whichever is longer.

1.4 Additional Compliance Information

1.4.1 The sanctions shall be assessed on a calendar quarter basis.

1.4.2 If any of R1.2 through R1.12 continues from one quarter to another, the number of days accumulated will be the contiguous calendar days from the beginning of the incident to the end of the incident. For example, in R1.8 if the 60 day repair period goes beyond the end of a quarter, the repair period does not reset at the beginning of the next quarter.

1.4.3 When calculating the adjusted in-service percentage, the PSS out of service hours do not include the time associated with R1.1 through R1.12.

1.4.4 The standard shall be applied on a generating unit by generating unit basis (a Generator Operator can be subject to a separate sanction for each non-compliant synchronous generating unit or to a single sanction for multiple machines that operate as one unit).

2. Violation Severity Levels

2.1. Lower: There shall be a Lower Level of non-compliance if the following condition exists:

2.1.1. PSS is in service less than 98% but at least 90% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.2. Moderate: There shall be a Moderate Level of non-compliance if the following condition exists:

2.2.1. PSS is in service less than 90% but at least 80% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.3. High: There shall be a High Level of non-compliance if the following condition exists:

2.3.1. PSS is in service less than 80% but at least 70% or more of all hours during which the synchronous generating unit is on line for each calendar quarter.

2.4. Severe: There shall be a Severe Level of non-compliance if the following condition exists:

2.4.1. PSS is in service less than 70% of all hours during which the synchronous generating unit is on line for each calendar quarter.

3. Violation Severity Levels for R2

3.1. Lower: There shall be a Lower Level of non-compliance if documentation is incomplete with any requirement R1.1 through R1.12.

3.2. Moderate: There shall be a Moderate Level of non-compliance if the Generator Operator does not have documentation to demonstrate compliance with any requirement R1.1 through R1.12.

3.3. High: Not Applicable

3.4. Severe: Not Applicable

E. Regional Differences

WECC Standard VAR-501-WECC-1 — Power System Stabilizer

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002b-1	
1	April 21, 2011	FERC Order issued approving VAR-501-WECC-1 (approval effective June 27, 2011)	

British Columbia Utilities Commission

Reliability Standards with Effective Dates adopted in British Columbia

Standard	Name	BCUC Order Adopting	Effective Date
BAL-001-0.1a	Real Power Balancing Control Performance	G-167-10	January 1, 2011
BAL-002-0	Disturbance Control Performance	G-67-09	June 8, 2009
BAL-003.0.1b	Frequency Response and Bias	G-167-10	January 1, 2011
BAL-004-0	Time Error Correction	G-67-09	June 8, 2009
BAL-004-WECC-01	Automatic Time Error Correction	G-167-10	January 1, 2011
BAL-005-0.1b	Automatic Generation Control	G-167-10	January 1, 2011
BAL-006-2	Inadvertent Interchange	R-1-13	April 15, 2013
BAL-STD-002-1	Operating Reserves	G-67-09	June 8, 2009
CIP-001-2a	Sabotage Reporting	R-1-13	January 15, 2013
CIP-002-3	Cyber Security – Critical Cyber Asset Identification	G-151-11	October 16, 2011
CIP-003-3	Cyber Security – Security Management Controls	G-151-11	October 16, 2011
CIP-004-3	Cyber Security – Personnel and Training	G-151-11	October 16, 2011
CIP-005-3a	Cyber Security – Electronic Security Perimeter(s)	R-1-13	July 15, 2013
CIP-006-3c	Cyber Security – Physical Security of Critical Cyber Assets	G-151-11	October 16, 2011
CIP-007-3	Cyber Security – Systems Security Management	G-151-11	October 16, 2011
CIP-008-3	Cyber Security – Incident Reporting and Response Planning	G-151-11	October 16, 2011
CIP-009-3	Cyber Security – Recovery Plans for Critical Cyber Assets	G-151-11	October 16, 2011
COM-001-1.1	Telecommunications	G-167-10	January 1, 2011
COM-002-2	Communication and Coordination	G-67-09	June 8, 2009
EOP-001-0	Emergency Operations Planning	G-67-09	June 8, 2009
EOP-002-3	Capacity and Energy Emergencies	R-1-13	July 15, 2013
EOP-003-1	Load Shedding Plans	G-67-09	June 8, 2009
EOP-004-1	Disturbance Reporting	G-67-09	June 8, 2009
EOP-005-1	System Restoration Plans	G-67-09	June 8, 2009
EOP-006-1	Reliability Coordination – System Restoration	G-67-09	June 8, 2009
EOP-008-0	Plans for Loss of Control Center Functionality	G-67-09	June 8, 2009
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	G-67-09	June 8, 2009
FAC-001-0	Facility Connector Requirements	G-67-09	June 8, 2009
FAC-002-1	Coordination of Plans for New Generation, Transmission, and End-User	R-1-13	July 15, 2013
FAC-003-1	Transmission Vegetation Management Program	G-67-09	June 8, 2009
FAC-501-WECC-1	Transmission Maintenance	R-1-13	April 15, 2013
FAC-008-1	Facility Ratings Methodology	G-67-09	June 8, 2009
FAC-009-1	Establish and Communicate Facility Ratings	G-67-09	June 8, 2009
FAC-010-2.1	System Operating Limits Methodology for the Planning Horizon	G-151-11	October 16, 2011
FAC-011-2	System Operating Limits Methodology for the Operations Horizon	G-167-10	January 1, 2011

Standard	Name	BCUC Order Adopting	Effective Date
FAC-013-1	Establish and Communicate Transfer Capability	G-67-09	June 8, 2009
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
INT-001-3	Interchange Information	G-67-09	June 8, 2009
INT-003-3	Interchange Transaction Implementation	R-1-13	April 15, 2013
INT-004-2	Dynamic Interchange Transaction Modifications	G-67-09	June 8, 2009
INT-005-3	Interchange Authority Distributes Arranged Interchange	G-151-11	October 16, 2011
INT-006-3	Response to Interchange Authority	G-151-11	October 16, 2011
INT-007-1	Interchange Confirmation	G-67-09	June 8, 2009
INT-008-3	Interchange Authority Distributes Status	G-151-11	October 16, 2011
INT-009-1	Implementation of Interchange	G-67-09	June 8, 2009
INT-010-1	Interchange Coordination Exemptions	G-67-09	June 8, 2009
IRO-001-1.1	Reliability Coordination Responsibilities and Authorities	G-167-10	January 1, 2011
IRO-002-2	Reliability Coordination – Facilities	R-1-13	April 15, 2013
IRO-003-2	Reliability Coordination – Wide Area View	G-67-09	June 8, 2009
IRO-004-2	Reliability Coordination – Operations planning	R-1-13	April 15, 2013
IRO-005-3a	Reliability Coordination – Current Day Operations	R-1-13	April 15, 2013
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-1	Qualified Transfer Path Unscheduled Flow (USF) Relief	R-1-13	April 15, 2013
IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments	R-1-13	April 15, 2013
IRO-009-1	Reliability Coordinator Actions to Operate Within IROLs	R-1-13	April 15, 2013
IRO-010-1a	Reliability Coordinator Data Specification and Collection	R-1-13	April 15, 2013
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability coordinators	G-67-09	June 8, 2009
IRO-015-1	Notification and Information Exchange	G-97-09	June 8, 2009
IRO-016-1	Coordination of Real-Time Activities	G-67-09	June 8, 2009
MOD-001-1a	Available Transmission System Capability	G-175-11	November 30, 2011
MOD-004-1	Capacity Benefit Margin	G-175-11	November 30, 2011
MOD-006-0.1	Qualified Path Unscheduled Flow Relief	G-67-09	January 1, 2011
MOD-007-0	Procedure for the Use of Capacity Benefit Margin ValueBenefit Margin	G-167-10	June 8, 2009
MOD-008-1	Transmission Reliability Margin Calculation Methodology	G-175-11	November 30, 2011
MOD-010-0	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	June 8, 2009
MOD-012-0	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	June 8, 2009
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demand, New Energy for Load, and Controllable Demand-Side Management	G-167-10	January 1, 2011
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load	G-167-10	January 1, 2011
MOD-018-0	Treatment of Non member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	G-67-09	June 8, 2009
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	G-167-10	January 1, 2011

Standard	**Name**	**BCUC Order Adopting**	**Effective Date**
MOD-020-0	Providing Interruptible Demands and Direct Control Load management Data to System Operators and Reliability Coordinators	G-67-09	June 8, 2009
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts.	R-1-13	April 15, 2013
MOD-028-1	Area Interchange Methodology	G-175-11	November 30, 2011
MOD-029-1a	Rated System Path Methodology	G-175-11	November 30, 2011
MOD-030-02	Flowgate Methodology	G-175-11	November 30, 2011
NUC-001-2	Nuclear Plant Interface Coordination	G-167-10	January 1, 2011
PER-001-0.1	Operating Personnel Responsibility and Authority	G-151-11	October 16, 2011
PER-003-0	Operating Personnel Credentials	G-67-09	June 8, 2009
PER-004-2	Reliability Coordination – Staffing	R-1-13	January 15, 2013
PER-005-1	System Personnel Training	R-1-13	R1: Jan. 15, 2015 R2: Jan. 15, 2015 R3: July 15, 2014 R3.1: Jan. 15, 2016
PRC-001-1	System Protection Coordination	G-67-09	June 8, 2009
PRC-004-1a	Analysis and Mitigation of Transmission and Generation Protection Misoperations	R-1-13	April 15, 2013
PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation	R-1-13	July 15, 2013
PRC-005-1a	Transmission and Generation Protection System Maintenance and Testing	R-1-13	April 15, 2013
PRC-007-0	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	June 8, 2009
PRC-008-0	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	June 8, 2009
PRC-009-0	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	June 8, 2009
PRC-010-0	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	June 8, 2009
PRC-011-0	Undervoltage Load Shedding system Maintenance and Testing	G-67-09	June 8, 2009
PRC-015-0	Special Protection System Data and Documentation	G-67-09	June 8, 2009
PRC-016-0.1	Special Protection System Misoperations	G-167-10	January 1, 2011
PRC-017-0	Special Protection System Maintenance and Testing	G-67-09	June 8, 2009
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting	G-67-09	June 8, 2009
PRC-021-1	Under Voltage Load Shedding Program Data	G-67-09	June 8, 2009
PRC-022-1	Under Voltage Load Shedding Program Performance	G-67-09	June 8, 2009
PRC-023-1	Transmission Relay Loadability	G-151-11	October 16, 2011
TOP-001-1a	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-002-2b	Normal Operations Planning	R-1-13	January 15, 2013
TOP-003-1	Planned Outage Coordination	R-1-13	April 15, 2013
TOP-004-2	Transmission Operations	G-167-10	January 1, 2011
TOP-005-2a	Operational Reliability Information	R-1-13	April 15, 2013
TOP-006-2	Monitoring System Conditions	R-1-13	April 15, 2013

Standard	Name	BCUC Order Adopting	Effective Date
TOP-007-0	Reporting System Operating Unit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	June 8, 2009
TOP-007-WECC-1	System Operating Limits	R-1-13	April 15, 2013
TOP-008-1	Response to Transmission Unit Violations	G-67-09	June 8, 2009
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)	G-167-10	January 1, 2011
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	R-1-13	January 15, 2013
TPL-003-0a	System Performance Following Loss of a Single Bulk Electric System Element (Category C)	G-151-11	October 16, 2011
TPL-004-0	System Performance Following Loss of a Single Bulk Electric System Element (Category D)	G-67-09	June 8, 2009
VAR-001-2	Voltage and Reactive Control	R-1-13	July 15, 2013
VAR-002-1.1b	Generator Operation for Maintaining Network Voltage Schedules	G-151-11	October 16, 2011
VAR-002-WECC-1	Automatic Voltage Regulators (AVR)	R-1-13	January 15, 2014
VAR-501-WECC-1	Power System Stabilizer (PSS)	R-1-13	April 15, 2013

British Columbia Utilities Commission

Reliability Standards with Effective Dates adopted in British Columbia

Standard	**Name**	**BCUC Order Adopting**	**Effective Date**
BAL-001-0.1a	Real Power Balancing Control Performance	G-167-10	January 1, 2011
BAL-002-0	Disturbance Control Performance	G-67-09	June 8, 2009
BAL-003.0.1b	Frequency Response and Bias	G-167-10	January 1, 2011
BAL-004-0	Time Error Correction	G-67-09	June 8, 2009
BAL-004-WECC-01	Automatic Time Error Correction	G-167-10	January 1, 2011
BAL-005-0.1b	Automatic Generation Control	G-167-10	January 1, 2011
BAL-006-2	Inadvertent Interchange	R-1-13	April 15, 2013
BAL-STD-002-1	Operating Reserves	G-67-09	June 8, 2009
CIP-001-2a	Sabotage Reporting	R-1-13	January 15, 2013
CIP-002-3	Cyber Security – Critical Cyber Asset Identification	G-151-11	October 16, 2011
CIP-003-3	Cyber Security – Security Management Controls	G-151-11	October 16, 2011
CIP-004-3	Cyber Security – Personnel and Training	G-151-11	October 16, 2011
CIP-005-3a	Cyber Security – Electronic Security Perimeter(s)	R-1-13	July 15, 2013
CIP-006-3c	Cyber Security – Physical Security of Critical Cyber Assets	G-151-11	October 16, 2011
CIP-007-3	Cyber Security – Systems Security Management	G-151-11	October 16, 2011
CIP-008-3	Cyber Security – Incident Reporting and Response Planning	G-151-11	October 16, 2011
CIP-009-3	Cyber Security – Recovery Plans for Critical Cyber Assets	G-151-11	October 16, 2011
COM-001-1.1	Telecommunications	G-167-10	January 1, 2011
COM-002-2	Communication and Coordination	G-67-09	June 8, 2009
EOP-001-0	Emergency Operations Planning	G-67-09	June 8, 2009
EOP-002-3	Capacity and Energy Emergencies	R-1-13	July 15, 2013
EOP-003-1	Load Shedding Plans	G-67-09	June 8, 2009
EOP-004-1	Disturbance Reporting	G-67-09	June 8, 2009
EOP-005-1	System Restoration Plans	G-67-09	June 8, 2009
EOP-006-1	Reliability Coordination – System Restoration	G-67-09	June 8, 2009
EOP-008-0	Plans for Loss of Control Center Functionality	G-67-09	June 8, 2009
EOP-009-0	Documentation of Blackstart Generating Unit Test Results	G-67-09	June 8, 2009
FAC-001-0	Facility Connector Requirements	G-67-09	June 8, 2009
FAC-002-1	Coordination of Plans for New Generation, Transmission, and End-User	R-1-13	July 15, 2013
FAC-003-1	Transmission Vegetation Management Program	G-67-09	June 8, 2009
FAC-501-WECC-1	Transmission Maintenance	R-1-13	April 15, 2013
FAC-008-1	Facility Ratings Methodology	G-67-09	June 8, 2009
FAC-009-1	Establish and Communicate Facility Ratings	G-67-09	June 8, 2009
FAC-010-2.1	System Operating Limits Methodology for the Planning Horizon	G-151-11	October 16, 2011
FAC-011-2	System Operating Limits Methodology for the Operations Horizon	G-167-10	January 1, 2011

Standard	Name	BCUC Order Adopting	Effective Date
FAC-013-1	Establish and Communicate Transfer Capability	G-67-09	June 8, 2009
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
INT-001-3	Interchange Information	G-67-09	June 8, 2009
INT-003-3	Interchange Transaction Implementation	R-1-13	April 15, 2013
INT-004-2	Dynamic Interchange Transaction Modifications	G-67-09	June 8, 2009
INT-005-3	Interchange Authority Distributes Arranged Interchange	G-151-11	October 16, 2011
INT-006-3	Response to Interchange Authority	G-151-11	October 16, 2011
INT-007-1	Interchange Confirmation	G-67-09	June 8, 2009
INT-008-3	Interchange Authority Distributes Status	G-151-11	October 16, 2011
INT-009-1	Implementation of Interchange	G-67-09	June 8, 2009
INT-010-1	Interchange Coordination Exemptions	G-67-09	June 8, 2009
IRO-001-1.1	Reliability Coordination Responsibilities and Authorities	G-167-10	January 1, 2011
IRO-002-2	Reliability Coordination – Facilities	R-1-13	April 15, 2013
IRO-003-2	Reliability Coordination – Wide Area View	G-67-09	June 8, 2009
IRO-004-2	Reliability Coordination – Operations planning	R-1-13	April 15, 2013
IRO-005-3a	Reliability Coordination – Current Day Operations	R-1-13	April 15, 2013
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-1	Qualified Transfer Path Unscheduled Flow (USF) Relief	R-1-13	April 15, 2013
IRO-008-1	Reliability Coordinator Operational Analyses and Real-time Assessments	R-1-13	April 15, 2013
IRO-009-1	Reliability Coordinator Actions to Operate Within IROLs	R-1-13	April 15, 2013
IRO-010-1a	Reliability Coordinator Data Specification and Collection	R-1-13	April 15, 2013
IRO-014-1	Procedures, Processes, or Plans to Support Coordination Between Reliability coordinators	G-67-09	June 8, 2009
IRO-015-1	Notification and Information Exchange	G-97-09	June 8, 2009
IRO-016-1	Coordination of Real-Time Activities	G-67-09	June 8, 2009
MOD-001-1a	Available Transmission System Capability	G-175-11	November 30, 2011
MOD-004-1	Capacity Benefit Margin	G-175-11	November 30, 2011
MOD-006-0.1	Qualified Path Unscheduled Flow Relief	G-67-09	January 1, 2011
MOD-007-0	Procedure for the Use of Capacity Benefit Margin ValueBenefit Margin	G-167-10	June 8, 2009
MOD-008-1	Transmission Reliability Margin Calculation Methodology	G-175-11	November 30, 2011
MOD-010-0	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	June 8, 2009
MOD-012-0	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	June 8, 2009
MOD-016-1.1	Documentation of Data Reporting Requirements for Actual and Forecast Demand, New Energy for Load, and Controllable Demand-Side Management	G-167-10	January 1, 2011
MOD-017-0.1	Aggregated Actual and Forecast Demands and Net Energy for Load	G-167-10	January 1, 2011
MOD-018-0	Treatment of Non member Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load	G-67-09	June 8, 2009
MOD-019-0.1	Reporting of Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators	G-167-10	January 1, 2011

Standard	Name	BCUC Order Adopting	Effective Date
MOD-020-0	Providing Interruptible Demands and Direct Control Load management Data to System Operators and Reliability Coordinators	G-67-09	June 8, 2009
MOD-021-1	Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts.	R-1-13	April 15, 2013
MOD-028-1	Area Interchange Methodology	G-175-11	November 30, 2011
MOD-029-1a	Rated System Path Methodology	G-175-11	November 30, 2011
MOD-030-02	Flowgate Methodology	G-175-11	November 30, 2011
NUC-001-2	Nuclear Plant Interface Coordination	G-167-10	January 1, 2011
PER-001-0.1	Operating Personnel Responsibility and Authority	G-151-11	October 16, 2011
PER-003-0	Operating Personnel Credentials	G-67-09	June 8, 2009
PER-004-2	Reliability Coordination – Staffing	R-1-13	January 15, 2013
PER-005-1	System Personnel Training	R-1-13	R1: Jan. 15, 2015 R2: Jan. 15, 2015 R3: July 15, 2014 R3.1: Jan. 15, 2016
PRC-001-1	System Protection Coordination	G-67-09	June 8, 2009
PRC-004-1a	Analysis and Mitigation of Transmission and Generation Protection Misoperations	R-1-13	April 15, 2013
PRC-004-WECC-1	Protection System and Remedial Action Scheme Misoperation	R-1-13	July 15, 2013
PRC-005-1a	Transmission and Generation Protection System Maintenance and Testing	R-1-13	April 15, 2013
PRC-007-0	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	June 8, 2009
PRC-008-0	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	June 8, 2009
PRC-009-0	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	June 8, 2009
PRC-010-0	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	June 8, 2009
PRC-011-0	Undervoltage Load Shedding system Maintenance and Testing	G-67-09	June 8, 2009
PRC-015-0	Special Protection System Data and Documentation	G-67-09	June 8, 2009
PRC-016-0.1	Special Protection System Misoperations	G-167-10	January 1, 2011
PRC-017-0	Special Protection System Maintenance and Testing	G-67-09	June 8, 2009
PRC-018-1	Disturbance Monitoring Equipment Installation and Data Reporting	G-67-09	June 8, 2009
PRC-021-1	Under Voltage Load Shedding Program Data	G-67-09	June 8, 2009
PRC-022-1	Under Voltage Load Shedding Program Performance	G-67-09	June 8, 2009
PRC-023-1	Transmission Relay Loadability	G-151-11	October 16, 2011
TOP-001-1a	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-002-2b	Normal Operations Planning	R-1-13	January 15, 2013
TOP-003-1	Planned Outage Coordination	R-1-13	April 15, 2013
TOP-004-2	Transmission Operations	G-167-10	January 1, 2011
TOP-005-2a	Operational Reliability Information	R-1-13	April 15, 2013
TOP-006-2	Monitoring System Conditions	R-1-13	April 15, 2013

Standard	Name	BCUC Order Adopting	Effective Date
TOP-007-0	Reporting System Operating Unit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	June 8, 2009
TOP-007-WECC-1	System Operating Limits	R-1-13	April 15, 2013
TOP-008-1	Response to Transmission Unit Violations	G-67-09	June 8, 2009
TPL-001-0.1	System Performance Under Normal (No Contingency) Conditions (Category A)	G-167-10	January 1, 2011
TPL-002-0b	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	R-1-13	January 15, 2013
TPL-003-0a	System Performance Following Loss of a Single Bulk Electric System Element (Category C)	G-151-11	October 16, 2011
TPL-004-0	System Performance Following Loss of a Single Bulk Electric System Element (Category D)	G-67-09	June 8, 2009
VAR-001-2	Voltage and Reactive Control	R-1-13	July 15, 2013
VAR-002-1.1b	Generator Operation for Maintaining Network Voltage Schedules	G-151-11	October 16, 2011
VAR-002-WECC-1	Automatic Voltage Regulators (AVR)	R-1-13	January 15, 2014
VAR-501-WECC-1	Power System Stabilizer (PSS)	R-1-13	April 15, 2013