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ORDER NUMBER
R-27-18A

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

and

British Columbia Hydro and Power Authority
Mandatory Reliability Standard TPL-001-4 Assessment Report

BEFORE:
W. M. Everett, QC, Commissioner

on June 28, 2018

ORDER

WHEREAS:

A. On May 3, 2017, the British Columbia Hydro and Power Authority (BC Hydro) filed the Mandatory Reliability Standard TPL-001-4 Assessment Report (Report) (Exhibit B-1) assessing Reliability Standard TPL-001-4 (TPL-001-4) developed by the North American Electric Reliability Corporation (NERC) and adopted in the United States (US) by the Federal Energy Regulatory Commission (FERC) on December 23, 2013. BC Hydro assessed TPL-001-4 excluding the accompanying Compliance Provisions. If adopted, TPL-001-4 would supersede the existing reliability standards previously adopted by the British Columbia Utilities Commission (BCUC);

B. Mandatory Reliability Standard (MRS) TPL-001-4 assessed by BC Hydro in the Report uses defined terms contained in the NERC Glossary of Terms Used in Reliability Standards, dated November 28, 2016. The Report includes an assessment of Requirements 1 to 8 (R1 to R8) in TPL-001-4 and a review of five new defined glossary terms intended for TPL-001-4 (Glossary Terms);

C. BC Hydro has acted as the Planning Authority/Planning Coordinator (PA/PC) for only the BC Hydro asset footprint. The PA/PC responsibilities for the province require clarification at this time. TPL-001-4 Requirement 7 (R7) pertains to the PC function and BC Hydro recommends that TPL-001-4 R7 be held in abeyance until the PC function is resolved;

D. In the Report, BC Hydro assessed TPL-001-4, with the exception of R7, and the new Glossary Terms and concludes that they are suitable for adoption in BC;

E. On November 24, 2017, BCUC Order R-48-17 directed BC Hydro to publish a Notice of MRS TPL-001-4 Assessment Report and Process for Public Comments and established the Regulatory Timetable for a public comment process (Exhibit A-1);

F. On December 7, 2017, comments were filed on behalf of the Commercial Energy Consumers Association of BC (Exhibit C1-1) stating that subject to further conflicting evidence arising from the BCUC's information request process and other stakeholders' comments, it is appropriate for the BCUC to adopt the standard and effective date as proposed by BC Hydro;

G. On December 7, 2017, FortisBC Inc. (FortisBC) submitted that it had no comments regarding the Report and on December 21, 2017, BC Hydro submitted it had no reply comments;

H. On January 18, 2018, the BCUC issued information requests (IRs) to BC Hydro in response to the Report;

I. On February 9, 2018, BC Hydro submitted its responses to the IRs (Exhibit B-4). BC Hydro stated that an earlier TPL-001-4 effective date outlined in BCUC IRs 1.1 to 1.3 would be acceptable to both BC Hydro and FortisBC. BC Hydro also stated that future detailed assessments using TPL-001-4 may identify additional system performance requirements and associated system upgrades. Such costs were not factored into the costs listed in the Report;

J. On February 20, 2018, FortisBC (Exhibit C2-2) submitted that it had no comments pertaining to BC Hydro's IR responses;

K. The BCUC did not review the recoverability of the estimated costs to adopt TPL-001-4 and the new Glossary Terms;

L. Although not assessed by BC Hydro, the BCUC considers that the Compliance Provisions of TPL-001-4 should be adopted to maintain compliance monitoring consistency with other jurisdictions that have adopted TPL-001-4 with the Compliance Provisions and finds it appropriate to provide an effective date for BC entities to come into compliance with TPL-001-4 and the Glossary Terms adopted in this order;

M. Pursuant to section 125.2(6) of the *Utilities Commission Act* (UCA), the BCUC must adopt the reliability standard addressed in the Report if it considers that the reliability standard is required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliablity standard; and

N. The BCUC has reviewed the information provided and considers that the adoption of TPL-001-4 and the Glossary Terms is warranted.

NOW THEREFORE pursuant to section 125.2 of the UCA, which provides the BCUC exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in BC, the BCUC orders as follows:

1. TPL-001-4 as set out in Attachment D, which is recommended for adoption in the Report, is adopted with effective dates as listed in Table 1 of Attachment A to this order and each reliability standard to be superseded by TPL-001-4 shall remain in effect until the effective date of TPL-001-4. All reliability standards listed in Attachment B to this order are in effect in BC as of the dates shown. Attachment B to this order also includes those reliability standards with effective dates held in abeyance to be assessed at a later date.
2. The Glossary Terms used in TPL-001-4 are adopted with effective dates as noted in Table 2 of Attachment A to this order. The Glossary Terms listed in Attachment C to this order are the Glossary Terms in effect in BC as of the effective dates indicated. The effective dates for the Glossary Terms listed in Attachment C supersede the effective dates that were included in any similar list appended to any previous order.

3. The Compliance Provisions that accompany TPL-001-4 are approved.

4. All entities to whom TPL-001-4 is applicable are directed to file with the BCUC semi-annual reports detailing the actual costs of implementing TPL-001-4 incurred to date, a comparison with estimated costs in the Report, explanations for cost variances and updated forecasts of costs. In the event of increased cost variances while implementing TPL-001-4, the report must address how these costs pertain to identified reliability issues, their impacts on the utilty system,and mitigating solutions. The semi-annual reports must be filed by the entities within 30 days of the end of each reporting period. The first semi-annual report must be filed with the BCUC on or before January 31, 2019.

DATED at the City of Vancouver, in the Province of British Columbia, this 11th day of July 2018.

BY ORDER

Original Signed By:

W. M. Everett, QC
Commissioner

Attachments

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

Table 1 British Columbia Utilities Commission Reliability Standard with Effective Dates as Adopted

	Standard	Standard Name	Effective Date	Type	Commission Approved Standard(s) Being Superseded[1]
1	TPL-001-4	Transmission System Planning Performance Requirements	**R1:** First day of first calendar quarter, 12 months after adoption (July 1, 2019). **R2–R6, R8:** First day of first calendar quarter, 24 months after adoption (July 1, 2020). For 84 calendar months beginning the first day of the first calendar quarter following BCUC approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4: - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element) - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element) - P2-1 - P2-2 (above 300 kV) - P2-3 (above 300 kV) - P3-1 through P3-5 - P4-1 through P4-5 (above 300 kV) - P5 (above 300 kV) **R7:** Adoption held in abeyance at this time.[2]	Revised	TPL-001-0.1 TPL-002-0b TPL-003-0b TPL-004-0a

[1] The Commission approved reliability standard(s) to be superseded by the revised reliability standard assessed.
[2] Unable to assess based on undefined Planning Coordinator/Planning Authority footprints and entities responsible.

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

Table 2 British Columbia Utilities Commission NERC Glossary Terms with Effective Dates as Adopted

	NERC Glossary Term[3]	Definition	Effective Date	Commission Approved Term to be Replaced or Retired
1	Bus-tie Breaker	A circuit breaker that is positioned to connect two individual substation bus configurations.	July 1, 2019	New Term
2	Consequential Load Loss	All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.	July 1, 2019	New Term
3	Long-Term Transmission Planning Horizon	Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.	July 1, 2019	New Term
4	Non-Consequential Load Loss	Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.	July 1, 2019	New Term
5	Planning Assessment	Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.	July 1, 2019	New Term

[3] FERC approved terms in the NERC Glossary of Terms as of November 28, 2016.

British Columbia Utilities Commission

Reliability Standards with Effective Dates adopted in British Columbia

Standard[1]	Name	Commission Order Adopting	Effective Date
BAL-001-2	Real Power Balancing Control Performance	R-14-16	July 1, 2016
BAL-002-2	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	R-39-17	January 1, 2018
BAL-002-WECC-2a	Contingency Reserve	R-39-17	July 26, 2017
BAL-003-1.1	Frequency Response and Frequency Bias Setting	R-32-16	October 1, 2016
BAL-004-0	Time Error Correction	G-67-09	November 1, 2010
BAL-004-WECC-2	Automatic Time Error Correction	R-32-14	October 1, 2014
BAL-005-0.2b	Automatic Generation Control	R-41-13	December 12, 2013 R2: Retired January 21, 2014[2]
BAL-006-2	Inadvertent Interchange	R-1-13	April 15, 2013
CIP-002-3[1]	Cyber Security – Critical Cyber Asset Identification	G-162-11	July 1, 2012
CIP-002-5.1	Cyber Security – BES Cyber System Categorization	R-38-15	October 1, 2018
CIP-003-3[1, 3, 4]	Cyber Security – Security Management Controls	G-162-11	July 1, 2012 R1.2, R3, R3.1, R3.2, R3.3, and R4.2: Retired January 21, 2014[2]
CIP-003-5[1]	Cyber Security – Security Management Controls	R-38-15	October 1, 2018
CIP-003-6	Cyber Security — Security Management Controls	n/a	Adoption held in abeyance at this time[5]
CIP-004-3a[1]	Cyber Security - Personnel & Training	R-32-14	August 1, 2014
CIP-004-5.1[1]	Cyber Security – Personnel & Training	R-38-15	October 1, 2018
CIP-004-6	Cyber Security — Personnel & Training	R-39-17	October 1, 2018 See BC CIP Version 5 Revisions Implementation Plan
CIP-005-3a[1, 3]	Cyber Security – Electronic Security Perimeter(s)	R-1-13	July 15, 2013 R2.6: Retired January 21, 2014[2]

1 "1" identifies a Reliability standard that is superseded by the revised/replacement reliability standard listed immediately below it as of the effective date(s) of the revised/replacement reliability standard.
2 On November 21, 2013, FERC Order 788 (referred to as Paragraph 81) approved the retiring of the reliability standard requirements.
3 Reliability standard is superseded by CIP-010-1 as of the CIP-010-1 effective date.
4 Reliability standard is superseded by CIP-011-1 as of the CIP-011-1 effective date.
5 BC Hydro recommends that the CIP-003-6 reliability standard be held in abeyance and be of no force or effect in BC due to technical suitability issues that will not improve reliability and instead place undue burden on responsible entities. When adopted by FERC, the NERC approved CIP-003-7(i) reliability standard will retire CIP-003-6. CIP-003-7(i) is anticipated to be assessed in the next MRS Assessment Report.

Standard[1]	Name	Commission Order Adopting	Effective Date
CIP-005-5	Cyber Security – Electronic Security Perimeter(s)	R-38-15	October 1, 2018
CIP-006-3c[1]	Cyber Security – Physical Security of Critical Cyber Assets	G-162-11	July 1, 2012
CIP-006-5[1]	Cyber Security – Physical Security of BES Cyber Systems	R-38-15	October 1, 2018
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems	R-39-17	October 1, 2018 See BC CIP Version 5 Revisions Implementation Plan
CIP-007-3a[1, 3, 4]	Cyber Security - Systems Security Management	R-32-14	August 1, 2014 R7.3: Retired January 21, 2014[2]
CIP-007-5[1]	Cyber Security – System Security Management	R-38-15	October 1, 2018
CIP-007-6	Cyber Security — System Security Management	R-39-17	October 1, 2018 See BC CIP Version 5 Revisions Implementation Plan
CIP-008-3[1]	Cyber Security – Incident Reporting and Response Planning	G-162-11	July 1, 2012
CIP-008-5	Cyber Security – Incident Reporting and Response Planning	R-38-15	October 1, 2018
CIP-009-3[1]	Cyber Security – Recovery Plans for Critical Cyber Assets	G-162-11	July 1, 2012
CIP-009-5[1]	Cyber Security – Recovery Plans for BES Cyber Systems	R-38-15	October 1, 2018
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems	R-39-17	October 1, 2018 See BC CIP Version 5 Revisions Implementation Plan
CIP-010-1[1]	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-38-15	October 1, 2018
CIP-010-2	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-39-17	October 1, 2018 See BC CIP Version 5 Revisions Implementation Plan
CIP-011-1[1]	Cyber Security – Information Protection	R-38-15	October 1, 2018
CIP-011-2	Cyber Security – Information Protection	R-39-17	October 1, 2018 See BC CIP Version 5 Revisions Implementation Plan
CIP-014-2	Physical Security	R-32-16	October 1, 2017 and as per BC-specific Implementation Plan
COM-001-1.1[1, 6]	Telecommunications	G-167-10	January 1, 2011
COM-001-2.1[1]	Communications	R-32-16	October 1, 2017
COM-001-3	Communications	R-39-17	R1, R2: October 1, 2017 R3 – R13: October 1, 2018

[6] Requirement 4 of the reliability standard is superseded by COM-002-4 as of the COM-002-4 effective date.

Standard[1]	Name	Commission Order Adopting	Effective Date
COM-002-4	Operating Personnel Communications Protocols	R-32-16	April 1, 2017
EOP-001-2.1b[7]	Emergency Operations Planning	R-32-14	August 1, 2014
EOP-002-3.1[7]	Capacity and Energy Emergencies	R-32-14	August 1, 2014
EOP-003-1[8]	Load Shedding Plans	G-67-09	November 1, 2010
EOP-003-2[9]	Load Shedding Plans		Adoption held in abeyance at this time[10]
EOP-004-3	Event Reporting	R-39-17	October 1, 2017
EOP-005-2	System Restoration and Blackstart Resources	R-32-14	August 1, 2015 R3.1: Retired January 21, 2014[2]
EOP-006-2	System Restoration Coordination	R-32-14	August 1, 2014
EOP-008-1	Loss of Control Center Functionality	R-32-14	August 1, 2015
EOP-010-1[11]	Geomagnetic Disturbance Operations	R-38-15	R1, R3: October 1, 2016 R2: At retirement of IRO-005-3.1a R3
EOP-011-1	Emergency Operations	R-39-17	October 1, 2018
FAC-001-2	Facility Interconnection Requirements	R-38-15	October 1, 2016
FAC-002-2	Facility Interconnection Studies	R-38-15	October 1, 2015
FAC-003-4	Transmission Vegetation Management	R-39-17	October 1, 2017
FAC-501-WECC-1	Transmission Maintenance	R-1-13	April 15, 2013
FAC-008-3	Facility Ratings	R-32-14	August 1, 2015 R4 and R5: Retired January 21, 2014[2]
FAC-010-3	System Operating Limits Methodology for the Planning Horizon	R-39-17	R1 – R4: October 1, 2017 R5: Retired
FAC-011-3	System Operating Limits Methodology for the Operations Horizon	R-39-17	October 1, 2017
FAC-013-1[12]	Establish and Communicate Transfer Capability	G-67-09	November 1, 2010

7 Reliability standard is superseded by EOP-011-1 as of the EOP-011-1 effective date.

8 Reliability standard would be superseded by EOP-003-2 if adopted in BC. Adoption of EOP-003-2 pending reassessment.

9 Reliability standard is superseded by EOP-011-1 as of the EOP-011-1 effective date in conjunction with PRC-010-2 Requirement 1 if adopted in BC. Adoption of PRC-010-2 pending reassessment.

10 Unable to assess based on undefined Planning Coordinator/Planning Authority footprints and entities responsible. The Commission Reasons for Decision for Order No. R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to BC.

11 Requirement 2 of the reliability standard will be effective upon the retirement of IRO-005-3.1a Requirement 3 which follows the effective date of IRO-002-4.

12 Reliability standard would be superseded by the FAC-013-2 if adopted in BC. Adoption of FAC-013-2 pending reassessment.

Standard[1]	Name	Commission Order Adopting	Effective Date
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon		Adoption held in abeyance at this time[10]
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
INT-004-3.1	Dynamic Transfers	R-38-15	R1, R2: October 1, 2015 R3: January 1, 2016
INT-006-4	Evaluation of Interchange Transactions	R-38-15	October 1, 2015
INT-009-2.1	Implementation of Interchange	R-38-15	October 1, 2015
INT-010-2.1	Interchange Initiation and Modification for Reliability	R-38-15	October 1, 2015
INT-011-1.1	Intra-Balancing Authority Transaction Identification	R-38-15	October 1, 2015
IRO-001-4	Reliability Coordination – Responsibilities	R-39-17	October 1, 2017
IRO-002-2[13]	Reliability Coordination – Facilities	R-1-13	April 15, 2013
IRO-002-4	Reliability Coordination – Monitoring and Analysis	R-39-17	October 1, 2017
IRO-003-2[13]	Reliability Coordination – Wide Area View	G-67-09	November 1, 2010
IRO-005-3.1a[13, 14]	Reliability Coordination - Current Day Operations	R-32-14	August 1, 2014
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-2	Qualified Transfer Path Unscheduled Flow (USF) Relief	R-38-15	October 1, 2015
IRO-008-2	Reliability Coordinator Operational Analyses and Real-time Assessments	R-39-17	October 1, 2017
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs	R-39-17	October 1, 2017
IRO-010-1a[13]	Reliability Coordinator Data Specification and Collection	R-1-13	April 15, 2013
IRO-010-2	Reliability Coordinator Data Specification and Collection	R-39-17	April 1, 2019
IRO-014-1[13]	Procedures, Processes, or Plans to Support Coordination Between Reliability coordinators	G-67-09	November 1, 2010
IRO-014-3	Coordination Among Reliability Coordinators	R-39-17	October 1, 2017
IRO-015-1[13]	Notification and Information Exchange	G-67-09	November 1, 2010
IRO-017-1	Outage Coordination	R-39-17	October 1, 2020

[13] See “IRO and TOP Reliability Standards Supersession Mapping” section below.
[14] Requirement 3 of the reliability standard is superseded by EOP-010-1 Requirement 2 as of the IRO-002-4 effective date.

Standard[1]	Name	Commission Order Adopting	Effective Date
IRO-018-1	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities	R-39-17	April 1, 2018
MOD-001-1a	Available Transmission System Capability	G-175-11	November 30, 2011
MOD-004-1	Capacity Benefit Margin	G-175-11	November 30, 2011
MOD-008-1	Transmission Reliability Margin Calculation Methodology	G-175-11	November 30, 2011
MOD-010-0[15]	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0[15]	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-020-0	Providing Interruptible Demands and Direct Control Load management Data to System Operators and Reliability Coordinators	G-67-09	November 1, 2010
MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
MOD-026-1	Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R6: October 1, 2015
MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R5: October 1, 2015
MOD-028-2	Area Interchange Methodology	R-32-14	August 1, 2014
MOD-029-2a	Rated System Path Methodology	R-39-17	October 1, 2017
MOD-030-3	Flowgate Methodology	R-39-17	October 1, 2017
MOD-031-2	Demand and Energy Data	R-39-17	April 1, 2018
MOD-032-1	Data for Power System Modeling and Analysis	R-38-15	Effective date held in abeyance[10]
MOD-033-1	Steady-State and Dynamic System Model Validation	R-38-15	Effective date held in abeyance[10]
NUC-001-3	Nuclear Plant Interface Coordination	R-38-15	January 1, 2016

[15] Reliability standard will be superseded by MOD-032-1 and MOD-033-1 if adopted in BC. Adoption of MOD-032-1 and MOD-033-1 pending reassessment.

Standard[1]	Name	Commission Order Adopting	Effective Date
PER-001-0.2[13]	Operating Personnel Responsibility and Authority	R-41-13	December 12, 2013
PER-002-0	Operating Personnel Training	G-67-09	November 1, 2010
PER-003-1	Operating Personnel Credentials	R-41-13	January 1, 2015
PER-004-2	Reliability Coordination – Staffing	R-1-13	January 15, 2013
PER-005-2	Operations Personnel Training	R-38-15	R1-R4, R6: October 1, 2016 R5: October 1, 2017
PRC-001-1.1(ii)	System Protection Coordination	R-32-16	October 1, 2016
PRC-002-2	Disturbance Monitoring and Reporting Requirements	R-32-16	R1, R5: April 1, 2017 R2-R4, R6-R11: staged as per BC-specific Implementation Plan R12: July 1, 2017
PRC-004-5(i)	Protection System Misoperation Identification and Correction	R-32-16	October 1, 2017
PRC-004-WECC-2	Protection System and Remedial Action Scheme Misoperation	R-39-17	October 1, 2017
PRC-005-1.1b[1, 18]	Transmission and Generation Protection System Maintenance and Testing	R-32-14	January 1, 2015
PRC-005-2[1]	Protection System Maintenance	R-38-15	R1, R2, R5: October 1, 2017 R3, R4: staged as per BC-specific Implementation Plan
PRC-005-2(i)[1]	Protection System Maintenance	R-32-16	R1, R2, R5: October 1, 2017 R3, R4: staged as per BC-specific Implementation Plan
PRC-005-6	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance	R-39-17	R1, R2, R5: October 1, 2019 R3, R4: See Implementation Plan
PRC-006-2[16]	Automatic Underfrequency Load Shedding		Adoption held in abeyance at this time[10]
PRC-007-0[17]	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0[18]	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010
PRC-009-0[17]	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	November 1, 2010

16 Reliability standard supersedes PRC-006-1 which has been held in abeyance due to the undefined Planning Coordinator/Planning Authority footprints and entities responsible.
17 Reliability standard will be superseded by PRC-006-2 if adopted in BC. Adoption of PRC-006-2 pending reassessment.
18 Reliability standard is superseded by PRC-005-6 as per the PRC-005-6 BC specific Implementation Plan.

Standard[1]	Name	Commission Order Adopting	Effective Date
PRC-010-0[1]	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	November 1, 2010 R2: Retired January 21, 2014[2]
PRC-010-2	Under Voltage Load Shedding		Adoption held in abeyance at this time[10]
PRC-011-0[18]	Undervoltage Load Shedding system Maintenance and Testing	G-67-09	November 1, 2010
PRC-015-1	Remedial Action Scheme Data and Documentation	R-39-17	October 1, 2017
PRC-016-1	Remedial Action Scheme Misoperations	R-39-17	October 1, 2017
PRC-017-1[18]	Remedial Action Scheme Maintenance and Testing	R-39-17	October 1, 2017
PRC-018-1[19]	Disturbance Monitoring Equipment Installation and Data Reporting	G-67-09	November 1, 2010
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	R-32-16	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-021-1[20]	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010
PRC-022-1[20]	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010 R2: Retired January 21, 2014[2]
PRC-023-2[1, 21]	Transmission Relay Loadability	R-41-13	R1-R5: For circuits identified by sections 4.2.1.1 and 4.2.1.4: January 1, 2016 For circuits identified by sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6: To be determined[10] R6: To be determined[10]
PRC-023-4	Transmission Relay Loadability	R-39-17	R1-R5 Circuits 4.2.1.1, 4.2.1.4: October 1, 2017 with the exception of Criterion 6 of R1 which will not become effective until PRC-025-1 R1 is completely effective in BC. Until then, PRC-023-2 R1, Criterion 6 will remain in effect. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: To be determined
PRC-024-2	Generator Frequency and Voltage Protective Relay Settings	R-32-16	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020

[19] Reliability standard is superseded by PRC-002-2 as of the PRC-002-2 effective date.
[20] Reliability standard is superseded by PRC-010-2 if adopted in B.C. Adoption of PRC-010-2 pending reassessment.
[21] PRC-023-2 Requirement 1, Criterion 6 only is superseded by PRC-025-1 as of PRC-025-1's 100 per cent Effective Date.

Standard[1]	Name	Commission Order Adopting	Effective Date
PRC-025-1	Generator Relay Loadability	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-026-1	Relay Performance During Stable Power Swings	n/a	Adoption held in abeyance at this time[10]
TOP-001-1a[13]	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-001-3	Transmission Operations	R-39-17	October 1, 2020
TOP-002-2.1b[13]	Normal Operations Planning	R-41-13	December 12, 2013
TOP-002-4	Operations Planning	R-39-17	October 1, 2020
TOP-003-1[13]	Planned Outage Coordination	R-1-13	April 15, 2013
TOP-003-3	Operational Reliability Data	R-39-17	April 1, 2019
TOP-004-2[13]	Transmission Operations	G-167-10	January 1, 2011
TOP-005-2a[13]	Operational Reliability Information	R-1-13	April 15, 2013
TOP-006-2[13]	Monitoring System Conditions	R-1-13	April 15, 2013
TOP-007-0[13]	Reporting System Operating Unit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	November 1, 2010
TOP-007-WECC-1a	System Operating Limits	R-38-15	October 1, 2015
TOP-008-1[13]	Response to Transmission Limit Violations	G-67-09	November 1, 2010
TOP-010-1	Real-time Reliability Monitoring and Analysis Capabilities	R-39-17	October 1, 2020
TPL-001-0.1[1, 22]	System Performance Under Normal (No Contingency) Conditions (Category A)	G-167-10	January 1, 2011
TPL-001-4	Transmission System Planning Performance Requirements	R-27-18	R1: July 1, 2019 R2-R6 and R8: July 1, 2020 R7: TBD[10]
TPL-002-0b[22]	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	R-1-13	January 15, 2013
TPL-003-0b[22]	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	R-32-14	August 1, 2014
TPL-004-0a[22]	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	R-32-14	August 1, 2014

[22] Reliability standard will be superseded by TPL-001-4 Requirements 2-6, and 8 as of their effective dates.

Standard[1]	Name	Commission Order Adopting	Effective Date
TPL-007-1	Transmission System Planned Performance for Geomagnetic Disturbance Events	n/a	Adoption held in abeyance at this time[10]
VAR-001-4.1	Voltage and Reactive Control	R-32-16	October 1, 2016
VAR-002-4	Generator Operation for Maintaining Network Voltage Schedules	R-32-16	October 1, 2016
VAR-002-WECC-2	Automatic Voltage Regulators (AVR)	R-32-16	October 1, 2016
VAR-501-WECC-2	Power System Stabilizer (PSS)	R-32-16	October 1, 2016

British Columbia Utilities Commission

IRO and TOP Reliability Standards
Supersession Mapping

This following mapping shows the supersession of Requirements for the following IRO, TOP, and PER reliability standards by the revised/replacement IRO and TOP reliability standards adopted or yet to be adopted in BC as of the effective date in the "BC Reliability Standards" section above:

- IRO-002-2 — Reliability Coordination - Facilities
- IRO-003-2 — Reliability Coordination - Wide-Area View
- IRO-004-2 — Reliability Coordination - Operations Planning
- IRO-005-3.1a — Reliability Coordination - Current Day Operations
- IRO-010-1a — Reliability Coordinator Data Specification and Collection
- IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators
- PER-001-0.2 — Operating Personnel Responsibility and Authority
- TOP-001-1a — Reliability Responsibilities and Authorities
- TOP-002-2.1b — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-2 — Transmission Operations
- TOP-005-2a — Operational Reliability Information
- TOP-006-2 — Monitoring System Conditions
- TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- TOP-008-1 — Response to Transmission Limit Violations

Standard IRO-002-2 — Reliability Coordination – Facilities	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirements R1, R3-R5, R7, and R8	IRO-002-4
Requirement R2	IRO-010-2
Requirement R6	IRO-008-2

Standard IRO-003-2 — Reliability Coordination - Wide-Area View	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
All Requirements	IRO-002-4

Standard IRO-004-2 — Reliability Coordination - Operations Planning	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
All Requirements	IRO-001-4 IRO-008-2

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirements R1-R3	IRO-002-4
Requirement R4	IRO-008-2
Requirements R5 and R8	IRO-001-4 IRO-002-4
Requirements R6 and R7	IRO-008-2 IRO-017-1

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R8	IRO-001-4 IRO-002-4
Requirement R9	IRO-002-4 IRO-010-2
Requirement R10	IRO-009-1 TOP-001-3
Requirement R11	MOD-001-2, Requirement R2 (pending FERC adoption in the US and subsequent assessment and adoption in BC.)
Requirement R12	IRO-008-2

Standard IRO-010-1a — Reliability Coordinator Data Specification and Collection	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
All Requirements	IRO-010-2

Standard IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-014-3 IRO-010-2
Requirements R2-R4	IRO-014-3

Standard IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirements R1 and R2	IRO-014-3
Requirement R3	IRO-010-2

Standard PER-001-0.2 — Operating Personnel Responsibility and Authority	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
All Requirements	TOP-001-3

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

Standard TOP-002-2.1b — Normal Operations Planning	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	TOP-001-3 TOP-002-4
Requirements R2, R5-R9, R12	TOP-002-4
Requirement R3	IRO-017-1 TOP-003-3
Requirement R4	IRO-017-1 IRO-008-2
Requirement R10	IRO-017-1 TOP-001-3 TOP-002-4 TOP-003-3
Requirement R11	TOP-001-3 TOP-002-4
Requirement R13	TOP-001-3 TOP-003-3
Requirements R14, R15, and R19	TOP-003-3
Requirements R16, R17, and R18	IRO-010-2

Standard TOP-003-1 — Planned Outage Coordination	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-010-2 TOP-003-3
Requirement R2	IRO-017-1 TOP-003-3
Requirement R3	TOP-001-3
Requirement R4	IRO-008-2 IRO-017-1

Standard TOP-004-2 — Transmission Operations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	TOP-001-3
Requirement R2	TOP-001-3 TOP-002-4
Requirements R3 and R4	TOP-001-3
Requirement R5	Retired
Requirement R6	IRO-017-1 TOP-001-3

Standard TOP-005-2a — Operational Reliability Information	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-010-2 TOP-003-3

Standard TOP-005-2a — Operational Reliability Information	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R2	TOP-003-3
Requirement R3	Retired

Standard TOP-006-2 — Monitoring System Conditions	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-010-2 TOP-001-3 TOP-003-3
Requirement R2	IRO-002-4 TOP-001-3
Requirement R3	IRO-010-2 TOP-003-3
Requirement R4	TOP-003-3
Requirement R5	IRO-002-4 TOP-001-3
Requirement R6	TOP-003-3
Requirement R7	IRO-002-4 TOP-001-3

Standard TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-008-2 TOP-001-3
Requirement R2	IRO-009-1 TOP-001-3
Requirement R3	EOP-003-2, Requirement 1 (adoption held in abeyance in BC due to PA/PC dependencies) IRO-009-1
Requirement R4	IRO-008-2

Standard TOP-008-1 — Response to Transmission Limit Violations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirements R1	EOP-003-2, Requirement 1 (adoption held in abeyance in BC due to PA/PC dependencies) TOP-001-3
Requirements R2 and R3	TOP-001-3
Requirement R4	TOP-001-3 TOP-002-4 TOP-003-3

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

Updated: R-27-18

Introduction:

This document is to be used in conjunction with the NERC Glossary dated November 28, 2016.

- The NERC Glossary terms listed in Table 1 below are effective in BC on the date specified in the “Effective Date” column.

- Table 2 below outlines the adoption history by the BCUC of the NERC Glossaries in BC.

- Any NERC Glossary terms and definitions in the NERC Glossary that are not approved by Federal Energy Regulatory Commission (FERC) on or before November 30, 2016 are of no force or effect in BC, with the exceptions of eight NERC Glossary terms and definitions intended for the BAL-002-2 reliability standard that were FERC approved in the NERC Glossary of Terms as of February 7, 2017 and assessed in MRS Assessment Report No. 10. These eight NERC Glossary terms are included in Table 1 below.

- Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in BC, with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in BC.

- The Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary have been adopted by the NERC Board of Trustees for use in regional standards and are of no force or effect in BC.

Table 1 BC Effective Date Exceptions to Definitions in the November 28, 2016 Version of the NERC Glossary

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Adjacent Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Alternative Interpersonal Communication	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Area Control Error (from NERC section of the Glossary)	ACE	Report No. 7	R-32-14	Adoption	October 1, 2014
Area Control Error (from the WECC Regional Definitions section of the Glossary)	ACE	Report No. 7	R-32-14	Retirement	October 1, 2014
Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Attaining Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Automatic Time Error Correction	-	Report No. 7	R-32-14	Adoption	October 1, 2014
Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
BES Cyber Asset[2]	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
BES Cyber Asset	BCA	Report No. 10	R-39-17	Adoption	October 1, 2018
BES Cyber System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
BES Cyber System Information	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Blackstart Capability Plan	-	Report No. 7	R-32-14	Retirement	August 1, 2015
Blackstart Resource[2]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Blackstart Resource	-	Report No. 10	R-39-17	Adoption	October 1, 2017

1 FERC approved terms in the NERC Glossary of Terms as of February 7, 2017; intended for BAL-002-2.
2 NERC Glossary term definition is superseded by the revised NERC Glossary term definition listed immediately below it as of the effective date(s) of the revised NERC Glossary term definition.
3 CIP Version 5 standards include CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1 and CIP-011-1.

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Bulk Electric System	BES	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System[2]	-	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Bus-tie Breaker	-	TPL-001-4 Report	R-27-18	Adoption -	July 1, 2019
Cascading	-	Report No. 10	R-39-17	Adoption	October 1, 2017
CIP Exceptional Circumstance	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
CIP Senior Manager	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Composite Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Composite Protection System	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Consequential Load Loss	-	TPL-001-4 Report	R-27-18	Adoption -	July 1, 2019
Contingency Event Recovery Period[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve Restoration Period[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Control Center	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Critical Assets	-	Report No. 9	R-32-16	Retirement	September 30, 2018
Critical Cyber Assets	-	Report No. 9	R-32-16	Retirement	September 30, 2018
Cyber Assets	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Demand-Side Management	DSM	Report No. 9	R-32-16	Adoption	October 1, 2016
Dial-up Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Distribution Provider	DP	Report No. 10	R-39-17	Adoption	October 1, 2017
Dynamic Interchange Schedule or Dynamic Schedule	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Electronic Access Control or Monitoring Systems	EACMS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Electronic Access Point	EAP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Electronic Security Perimeter	ESP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Element	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Energy Emergency	-	Report No. 9	R-32-16	Adoption	October 1, 2016
External Routable Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Frequency Bias Setting	-	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Measure	FRM	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Obligation	FRO	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Sharing Group	FRSG	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Generator Operator	GOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Generator Owner	GO	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	GMD	Report No. 10	R-39-17	Adoption	To be determined[4]
Interactive Remote Access	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Interchange Authority	IA	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnected Operations Service	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection Reliability Operating Limit	IROL	Report No. 6	R-41-13	Adoption	December 12, 2013
Intermediate Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Intermediate System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Interpersonal Communication	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Load-Serving Entity	LSE	Report No. 10	R-39-17	Adoption	October 1, 2017
Long-Term Transmission Planning Horizon	-	TPL-001-4 Report	R-27-18	Adoption -	July 1, 2019
Low Impact BES Cyber System Electronic Access Point[5]	LEAP	Report No. 10		Adoption	Not recommended for adoption in BC at this time
Low Impact External Routable Connectivity[5]	LERC	Report No. 10		Adoption	Not recommended for adoption in BC at this time
Minimum Vegetation Clearance Distance	MVCD	Report No. 7	R-32-14	Adoption	August 1, 2015
Misoperation	-	Report No. 9	R-32-16	Adoption	October 1, 2017
Most Severe Single Contingency[1]	MSSC	Report No. 10	R-39-17	Adoption	January 1, 2018

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

[5] Intended for CIP-003-6 and to be held in abeyance and be of no force or effect in BC due to technical suitability issues. When adopted by FERC, the NERC-approved CIP-003-7(i) will retire the NERC Glossary terms. CIP-003-7(i) is anticipated to be assessed in the next MRS Assessment Report.

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Native Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Non-Consequential Load Loss	-	TPL-001-4 Report	R-27-18	Adoption -	July 1, 2019
Operating Instruction	-	Report No. 9	R-32-16	Adoption	April 1, 2017
Operational Planning Analysis[2]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Operational Planning Analysis[2]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Operational Planning Analysis	-	Report No. 9	R-32-16	Adoption	October 1, 2016
Operations Support Personnel	-	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 5 of the PER-005-2 standard where this term is referenced
Physical Access Control Systems	PACS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Physical Security Perimeter	PSP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Planning Assessment	-	TPL-001-4 Report	R-27-18	Adoption -	July 1, 2019
Planning Authority	PA	Report No. 10	R-39-17	Adoption	October 1, 2017
Point of Receipt	POR	Report No. 10	R-39-17	Adoption	October 1, 2017
Pre-Reporting Contingency Event ACE Value[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Protected Cyber Assets[2]	PCA	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Protected Cyber Assets	PCA	Report No. 10	R-39-17	Adoption	October 1, 2018
Protection System	-	Report No. 6	R-41-13	Adoption	January 1, 2015 for each entity to modify its protection system maintenance and testing program to reflect the new definition (to coincide with recommended effective date of PRC-005-1b) and until the end of the first complete maintenance and testing cycle to implement any additional maintenance and testing for battery chargers as required by that entity's program

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Protection System Maintenance Program	PSMP	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 1 of the PRC-005-2 standard where this term is referenced
Protection System Maintenance Program *(PRC-005-4)*[6]	PSMP	Report No. 9		-	Not recommended for adoption in BC at this time
Protection System Maintenance Program *(PRC-005-6)*	PSMP	Report No. 10	R-39-17	Adoption	October 1, 2019
Pseudo-Tie	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Reactive Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real-time Assessment[2]	-	Report No. 6	R-41-13	Adoption	January 1 , 2014
Real-time Assessment	-	Report No. 9	R-32-16	Adoption	October 1, 2016
Reliability Adjustment Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Reliability Coordinator	RC	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliability Directive	-	Report No. 9	R-32-16	Retirement	July 18, 2016
Reliability Standard[2]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliability Standard	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliable Operation[2]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliable Operation	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Relief Requirement (WECC Regional Term)	-	Report No. 8	R-38-15	Adoption	Align with effective date of IRO-006-WECC-2 standard where this term is referenced
Remedial Action Scheme	RAS	Report No. 1	G-67-09	Adoption	June 4, 2009
Remedial Action Scheme	RAS	Report No. 9		-	To be determined[4]
Removable Media	-	Report No. 10	R-39-17	Adoption	October 1, 2018

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

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Reportable Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Reportable Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] where this term is referenced
Request for Interchange	RFI	Report No. 8	R-38-15	Adoption	October 1, 2015
Reserve Sharing Group	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reserve Sharing Group Reporting ACE[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Resource Planner	RP	Report No. 10	R-39-17	Adoption	October 1, 2017
Sink Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Source Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Special Protection System (Remedial Action Scheme)	SPS	Report No. 1	G-67-09	Adoption	June 4, 2009
Special Protection System (Remedial Action Scheme)	SPS	Report No. 10	R-39-17	Adoption	Held in abeyance due to PC dependancies
System Operating Limit	-	Report No. 10	R-39-17	Adoption	October 1, 2017
System Operator	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards[3] as reference is made to the term Control Center as part of the definition of System Operator. “Control Center” is in turn referenced from the CIP Version 5 standards.
Total Internal Demand	-	Report No. 9	R-32-16	Adoption	October 1, 2016
Transient Cyber Asset	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Transmission Customer	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Operator	TOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Owner	TO	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Planner	TP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Service Provider	TSP	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	Commission Order Number	Commission Adoption or Retirement	Effective Date
Under Voltage Load Shedding Program	-	Report No. 9		-	To be determined[4]
Right-of-Way	ROW	Report No. 7	R-32-14	Adoption	August 1, 2015
TLR (Transmission Loading Relief) Log	-	Report No. 7	R-32-14	Adoption	August 1, 2014
Vegetation Inspection	-	Report No. 7	R-32-14	Adoption	August 1, 2015

Table 2 NERC Glossary Adoption History in BC

<table>
<tr><th>NERC Glossary of Terms Version Date</th><th>Assessment Report Number</th><th>Commission Order Adoption Date</th><th>Commission Order Adopting</th><th>Notes pertaining to NERC Glossary Effective Dates</th></tr>
<tr><td>February 12, 2008</td><td>Report No. 1</td><td>June 4, 2009</td><td>G-67-09</td><td rowspan="11">1. The NERC Glossaries listed became effective as of the date of the respective Commission Orders adopting them. See the exception of the BAL-001-2 Glossary Terms within the NERC Glossary dated December 7, 2015.[1]

2. Specific effective dates of new and revised NERC Glossary terms adopted in a Commission Order appear in attachments to the Order. Each Glossary term to be superseded by a revised Glossary term adopted in the Order shall remain in effect until the effective date of the Glossary term superseding it.

3. NERC Glossary terms which have not been approved by FERC are of no force or effect in BC.

4. Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in BC, with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in BC.

5. The Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary of Terms are of no force or effect in BC.</td></tr>
<tr><td>April 20, 2010</td><td>Report No. 2</td><td>November 10, 2010</td><td>G-167-10</td></tr>
<tr><td>August 4, 2011</td><td>Report No. 3</td><td>September 1, 2011</td><td>G-162-11 replacing G-151-11</td></tr>
<tr><td>December 13, 2011</td><td>Report No. 5</td><td>January 15, 2013</td><td>R-1-13</td></tr>
<tr><td>December 5, 2012</td><td>Report No. 6</td><td>December 12, 2013</td><td>R-41-13</td></tr>
<tr><td>January 2, 2014</td><td>Report No. 7</td><td>July 17, 2014</td><td>R-32-14</td></tr>
<tr><td>October 1, 2014</td><td>Report No. 8</td><td>July 24, 2015</td><td>R-38-15</td></tr>
<tr><td>December 7, 2015</td><td>BAL-001-2</td><td>April 21, 2016</td><td>R-14-16</td></tr>
<tr><td>December 7, 2015</td><td>Report No. 9[2]</td><td>July 18, 2016</td><td>R-32-16</td></tr>
<tr><td>November 28, 2016</td><td>Report No. 10</td><td>July 26, 2017</td><td>R-39-17</td></tr>
<tr><td>November 28, 2016[3]</td><td>Report TPL-001-4</td><td>June 28, 2018</td><td>R-27-18</td></tr>
</table>

[1] The BAL-001-2 Glossary Terms (Interconnection, Regulation Reserve Sharing Group, Reporting Ace and Reserve Sharing Group Reporting Ace) became effective as of July 1, 2016.

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

[3] Additional Glossary Terms pertaining to TPL-001-4 adopted by this order.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date*:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.
      iii. Wildfires.
      iv. Severe weather, e.g., hurricanes, tornadoes, etc.
      v. A successful cyber attack.
      vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
   b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. British Columbia Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required</u>

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

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

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

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

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

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	