BC Hydro
Power smart

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May 31, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Mandatory Reliability Standards (MRS)
Planning Coordinator Assessment Report (Report)

BC Hydro writes to the BCUC to provide the Planning Coordinator Assessment Report dated May 31, 2021 pursuant to Section 125.2(3) of the *Utilities Commission Act*. BC Hydro is providing an electronic copy of the Report to registered entities in the British Columbia (**B.C.**) MRS program.

The Report presents the reliability impacts, suitability, standard applicability and potential costs of adopting the 12 reliability standards referencing the Planning Coordinator (**PC**) function that are new or held in abeyance in B.C (**PC Standards**). In the Report, BC Hydro recommends that 11 of the 12 PC Standards are suitable for adoption in B.C. at this time and also recommends the retirement of one standard referencing the PC function. BC Hydro also recommends that four terms contained in the North Amercian Electric Reliability Corporation Glossary of Terms that have been held in abeyance be adopted in B.C.

The Report assessment and recommendations made are predicated on two assumptions:

1. BC Hydro will be the PC for its own BES assets only at this time and consideration will be given in future to the potential expansion of BC Hydro's PC footprint to include entities that are interconnected to BC Hydro's system that are also registered under the BCUC's MRS program, with the exception of FortisBC Inc.; and
2. FortisBC Inc. will be the PA/PC for its own BES assets.

BC Hydro notes that these assumptions are not conclusive of how registration for the PA and PC functions will occur in B.C. as this is a matter for the BCUC to determined through a separate process. These assumptions have only been made for the purpose of assessing the PC Standards.

On June 25, 2021, BC Hydro will file its plan for implementing the PC function for its footprint, including the timing of its proposed registration for the PC function, with the Commission for information. This plan will also identify the timing for engaging other entities interconnected to BC Hydro's system that are registered in the B.C. MRS Program on the potential for BC Hydro to become the PC for those entities.

For further information, please contact Lynne Foster at 604-623-3918 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

al/rh

Enclosure

BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

May 31, 2021

Table of Contents

1 Introduction 1
1.1 Purpose of Report 1
1.2 Contents of the Report 4
2 Proposed Process 4
2.1 Draft Order 4
2.2 Proposed Process 5
3 Special Considerations 6
3.1 Accelerated Retirement of the FAC-013-1 Standard 6
3.2 Non-adoption of the EOP-003-2 Standard 7
3.3 B.C. TPL-001-5.1 Implementation Plan 8
3.4 B.C. TPL-007-4 Implementation Plan 9
4 Standards Assessment Process used in the Report 10
4.1 Identification of Standards for Review and Inclusion in the Report 10
4.2 Feedback Sought Through Consultation 11
4.2.1 First Consultation 11
4.2.2 Shift in Assumptions 13
4.2.3 Second Consultation 15
5 Assessment of Individual Standards 17
5.1 PC Standards 17
5.2 Analytical Approach to Assessment of Reliability Impact, Suitability, Cost of Adoption and Application 19
5.2.1 Analytical Approach in Assessing Adverse Reliability Impacts 20
5.2.2 Analytical Approach for the Suitability Assessment 20
5.2.3 Analytical Approach for the Cost Assessment 21
5.2.4 Analytical Approach for the Application of the Reliability Standards 21
5.3 Initial Screening of the Standards for Adverse Reliability Impacts and Suitability 22
5.4 Summary of Final Assessment of the Standards Assessed in the Report 27
6 NERC Glossary of Terms 34
6.1 Non-FERC Approved and Remanded/Retired NERC Glossary Terms 36
6.2 NERC Glossary Terms Assessed by BC Hydro 36

6.3 Initial Screening of NERC Glossary Terms for Adverse Reliability Impact and Suitability 38
6.4 Summary of Final Assessment of the NERC Glossary Terms Assessed in the Report 38
7 Conclusions 41

List of Tables

Table 1 B.C. MRS Program Registered Entity List 11
Table 2 Initial Screening of PC Standards and the Retired Standard for Adverse Reliability Impact and Suitability 24
Table 3 Final Assessment Summary of PC Standards and the Retired Standard 28
Table 4 Initial Screening of NERC Glossary Terms for Adverse Reliability Impact and Suitability 38
Table 5 Final Assessment Summary of NERC Glossary Terms 39

Appendices

Appendix A-1 List of Assessed Reliability Standards and NERC Glossary Terms
Appendix A-2 Reliability Standards Assessed by BC Hydro
Appendix B NERC Glossary of Terms used in Reliability Standards - Updated October 8, 2020
Appendix C-1 BC Hydro Feedback Survey Forms
Appendix C-2 Instructions for Registered Entities
Appendix C-3 External Stakeholder Feedback
Appendix D Draft Order

1 Introduction

1.1 Purpose of Report

Pursuant to the requirements of section 125.2(3) of the *Utilities Commission Act* (**UCA**), British Columbia Hydro and Power Authority (**BC Hydro**) provides this Mandatory Reliability Standards (**MRS**) Planning Coordinator Assessment Report (**Report**), pertaining to the Bulk Electric System (**BES**) in B.C. to the British Columbia Utilities Commission (**BCUC** or **Commission**) for consideration. This Report has been filed separately from BC Hydro's Assessment Report No. 14 because it is focused on an assessment of the impact associated with the adoption and implementation of standards that relate to the Planning Coordinator (**PC**) function in British Columbia.

Currently, there are no registered PCs in the B.C. MRS program. BC Hydro is registered as a Planning Authority (**PA**) in B.C. for its own footprint and has been registered for this function since the inception of MRS in B.C. In [2013], the PC function was introduced into the North American Electric Reliability Corporation (**NERC**) MRS and was intended to replace the PA function. The NERC Glossary of Terms (**Glossary**) defined PC as being the same as PA.

The issue of the new PC function and its adoption in B.C. was first identified by BC Hydro while it was assessing the new PRC-023-2 reliability standard.

- On April 18, 2013, BC Hydro submitted a letter (**PC Letter**) to the BCUC advising that there was no PC functional registration in the B.C. MRS Program Rules of Procedure and therefore no entity was registered as a PC in B.C.[1] In the PC Letter, BC Hydro recommended the BCUC undertake an independent process to: establish a PC functional registration; determine which entities in

[1] http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/reference-documents/MRS_PCA_RPT_2021_2013_04_18_BCH_MRS_PC_Funct_Role.pdf.

B.C. should be registered as "Responsible Entities" for the new PC function; and establish effective dates for the B.C. MRS requirements relating to the PC function which would have reflected the time needed for entities to become compliant with those MRS.

- On May 22, 2013, the BCUC issued letter L-29-13A seeking input from BC Hydro and other registered entities as to "the extent of the PA/PC operations/footprint in BC".[2]
- In the Reasons for Decisions to Order No. R-41-13 related to MRS Assessment Report No. 6, the BCUC found that the "PA/PC question" was beyond the scope of the MRS Assessment Report No. 6 review process and indicated that a separate process would be established to consider the PA/PC matter as it pertains to B.C.[3]
- That separate process, as contemplated by BC Hydro and the BCUC in 2013, has not been convened and instead, over the ensuing period, BC Hydro has assessed and the BCUC has adopted those reliability standards that reference the PA/PC function but are able to be implemented by other registered functions[4] and has held in abeyance any reliability standards with sole dependencies on the PA/PC function.[5]

BC Hydro is now undertaking the assessment of the PC MRS to enable their adoption in B.C. As a result, BC Hydro has undertaken a broad review of all PC-related standards and/or requirements that have been held in abeyance in B.C.

2 https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/118904/index.do?q=L-29-13

3 Refer to BCUC Order No. R-41-13.

4 For example, where a standard relates to and contains obligations for a number of registered functions (TO, GO and PC), BC Hydro has recommended the standard be adopted as they are not solely dependent on the actions of the PC.

5 For example, any standards that relate exclusively to the PC function and that require a registered PC to perform the actions have been held in abeyance in B.C. and not been adopted for implementation.

and assessed those standards and/or requirements for adoption. This includes an assessment of:

- Entire standards that have been held in abeyance[6] and/or standards that are currently in effect in B.C., but which contain one or more requirements that are related to the PC function that have been held in abeyance by the BCUC under previous orders;[7] and
- Any new Federal Energy Regulatory Commission (**FERC**) approved standards that relate to the PC function which are being assessed in this report as opposed to Assessment Report No. 14 (filed by BC Hydro on April 30, 2021). This includes revisions to currently adopted standards and revisions to standards currently held in abeyance.[8] These revisions are being put forward for adoption as they fall within the same assessment period as Assessment Report No. 14.[9]

For the purposes of this Report, BC Hydro refers to these standards collectively as the **PC Standards**. Table 2 within section 1.1 shows the 12 PC Standards.

6 Standards EOP-003-2 and FAC-013-2 were held in abeyance per BCUC Order No. R-32-14; Standard MOD-032-1 was held in abeyance per BCUC Order No. R-38-15; Standard PRC-010-2 was held in abeyance per BCUC Order No. R-32-16; and Standard PRC-026-1 was held in abeyance under BCUC Order No. R-39-17.

7 Standard PRC-012-2 was adopted per BCUC Order No. R-33-18, however, PRC-012-2 R1 Attachment 1, Section II Parts 6(d) and 6(e), R2 Attachment 2, Section I Parts 7(d) and 7(e), and R4 are held in abeyance in B.C.; Standard PRC-023-2 was adopted per BCUC Order No. R-41-13, however PRC-023-2 Requirements R1 to R5 for Criterion 6 only in relation to circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 as identified per R6 and R6 are held in abeyance in B.C.; Standard PRC-023-4 was adopted per BCUC Order No. R-39-17, however PRC-023-4 Requirements R1-R5 for circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6 are held in abeyance in B.C.

8 Standard TPL-001-5.1 is a revision to a currently adopted standard in B.C. (TPL-001-4). Standards MOD-033-2, PRC-006-4, and TPL-007-4 are revisions to standards held in abeyance in B.C. (MOD-033-1 per BCUC Order No. R-38-15, PRC-006-3 per BCUC Order No. R-33-18, PRC-006-2 per BCUC Order No. R32-16, PRC-006-1 per BCUC Order No. R-32-14, TPL-007-3 per BCUC Order No. R-19-20 respectively, and TPL-007-1 per BCUC Order No. R-39-17).

9 This assessment period covers standards that were FERC approved with an effective Order between, and including, December 1, 2019 and November 30, 2020 (the **2020 Assessment Period**). Pursuant to BCUC Order R-6-21 and in accordance with the Mandatory Reliability Standards Regulation issued under the UCA, the BCUC granted BC Hydro an extension of the timeline required for consideration of the new PC Standards that would have otherwise been considered in Assessment Report No. 14 by BC Hydro to May 31, 2021.

In addition, in this Report, BC Hydro:

- Has assessed the retirement of one reliability standard related to the PC function; and
- Is recommending the adoption of four new defined terms (**PC Terms**) from the NERC Glossary dated October 8, 2020.

1.2 Contents of the Report

The Report is organized as follows:

- Section 2.1 provides an outline of the Draft Order and recommends a proposed assessment process for this Report;
- Section 3 sets out certain special considerations BC Hydro raises for the BCUC's consideration;
- Section 4 explains BC Hydro's assessment process, including its consultation with stakeholders;
- Section 5 summarizes BC Hydro's approach to assessing the PC Standards, including the results of that assessment;
- Section 6 summarizes the results of the assessment of the PC Terms using the approach as described in section 5; and
- Section 7 provides BC Hydro's conclusions.

2 Proposed Process

2.1 Draft Order

The Draft Order attached to the Report as Appendix D, includes the following draft attachments:

- Attachment A – Provides a table that lists the PC Standards, the BCUC approved reliability standards to be superseded by the PC Standards, and the retired reliability standard. Attachment A also provides a table that lists the PC Terms to be adopted in B.C. The tables include recommended effective dates for these changes to allow for an implementation period for registered entities to adjust business processes to achieve compliance;
- Attachment B – Provides a list of all the reliability standards that would be in force in B.C., including those assessed in the Report. The table also provides the BCUC Order under which each of the reliability standards was adopted and their effective dates;
- Attachment C – For ease of reference, BC Hydro is including Table 1 in Attachment C, which lists all the B.C.-specific exceptions to the NERC Glossary, starting from MRS Assessment Report No. 6;[10] and
- Attachment D – Includes B.C.-specific versions of the TPL-001-5.1 Implementation Plan and the TPL-007-4 Implementation Plan to be implemented in B.C., as discussed in detail in sections 3.3 and 3.4, respectively.

2.2 Proposed Process

The BCUC is obligated by section 125.2(5) of the UCA to make the Report publicly available and to consider any comments it receives in respect of the Report.

To make the Report publicly available, BC Hydro will publish a notice of the Report on its public website and send a letter of notification to all B.C. MRS registered entities with whom it originally consulted in connection with the preparation of the Report, as listed in Table 1, section 4.2.

[10] Refer to Table 2 in Appendix D, Attachment C: All BCUC Orders prior to Order No. R-41-13 for MRS Assessment Report No. 6 adopted the entire NERC Glossary effective as of the date of the Order.

BC Hydro will respond to any comments on the Report. The BCUC would then determine whether all the issues raised in the comment process have been dealt with to its satisfaction. If so, no further process would be required. If not, then a written process could be established to deal with any outstanding issues. Upon completion of the process, the BCUC would determine whether the PC Standards and PC Terms should be adopted in B.C. and whether the retired reliability standard should be retired.

3 Special Considerations

BC Hydro raises the following special considerations for the Report:

3.1 Accelerated Retirement of the FAC-013-1 Standard

FERC Order No. 873 became effective in the U.S. on December 14, 2020 which retired the FAC-013-2 standard as part of a group of retired reliability standards on the same day. The FAC-013-2 standard is one of the PC Standards being assessed in this Report. It is currently held in abeyance in B.C. If adopted, it would completely supersede the currently adopted and effective FAC-013-1 reliability standard. However, both FAC-013-1 and FAC-013-2 are retired in the U.S.

The FAC-013-2 and preceding FAC-013-1 reliability standards address the establishment of Transfer Capabilities by Reliability Coordinators and Planning Authorities and the communication of Transfer Capabilities to other applicable entities. FERC's reasons for retirement cited that associated requirements either (1) provide little to no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards.

BC Hydro is therefore recommending that the FAC-013-2 standard currently held in abeyance, not be adopted under this Report as there is no perceived reliability benefit to B.C. nor would it be in the public interest. BC Hydro is also recommending the accelerated retirement of the currently effective FAC-013-1 reliability standard to align with the U.S. instead of waiting until the 2021 Assessment Period to recommend retirement under Assessment Report No. 15.

3.2 Non-adoption of the EOP-003-2 Standard

The EOP-003-2 standard, currently held in abeyance in B.C. due to PC dependencies, has been completely superseded by a combination of Requirements 1 and 2 of the EOP-011-1 standard and Requirement 1 of the PRC-010-2 standard.[11] Specifically:

- The EOP-011-1 standard was adopted in B.C. under BCUC Order No. R-39-17 and has been effective since October 1, 2018; however, it does not reference the PA/PC function. EOP-011-1 Requirements 1 and 2 supersede EOP-003-2 Requirements 1, 3, 5, 6, and 8; and
- The PRC-010-2 standard, previously held in abeyance in B.C., is one of the PC Standards being assessed in this Report and is recommended for adoption with an implementation timeframe of the first day of the first calendar quarter, 12 months after BCUC adoption. PRC-010-2 Requirement 1 supersedes EOP-003-2 Requirements 2, 4, and 7.

The EOP-003-2 standard addresses load shedding plans and requires Transmission Operators or Balancing Authorities to have the capability and authority to shed load rather than risk an uncontrolled failure of an Interconnection.

If the EOP-003-2 standard were to be adopted under this Report, the implementation timeframe as indicated per the U.S. FERC approved NERC developed Implementation Plan would be the same as the PRC-010-2 recommended

[11] Per the NERC Project 2009-03 – Emergency Operations mapping document and NERC Project 2008-02 Undervoltage Load Shedding mapping document.

implementation timeframe such that both standards would come in to effect in B.C. on the first day of the first calendar quarter, 12 months after BCUC adoption. This would effectively render the EOP-003-2 standard as being completely superseded immediately upon its potential effective date in B.C.

Therefore, for administrative ease, BC Hydro does not recommend adoption of the EOP-003-2 standard.

3.3 B.C. TPL-001-5.1 Implementation Plan

In this Report, BC Hydro recommends the adoption of the TPL-001-5.1 standard. In connection with that recommendation, BC Hydro also recommends a B.C.-specific version of the FERC approved TPL-001-5 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards. BC Hydro has drafted a B.C.-specific version of this Implementation Plan to align it with the B.C. MRS program. The B.C. Implementation Plan is based on the Implementation Plan developed by NERC and approved by FERC, and both clean and redline drafts showing the changes proposed for the B.C.-specific version in relation to the respective NERC Implementation Plan are included in Attachment D-1 to Appendix D for the BCUC's review.

The B.C. TPL-001-5.1 specific Implementation Plan provides clarity to entities that adoption and implementation of the MOD-032-1 reliability standard is a pre-requisite to the implementation of TPL-001-5.1 and also provides clarity on implementation times for initial compliance with a subset of TPL-001-5.1 requirements. MOD-032-1 is one of the PC Standards being assessed in this Report. Adopting the B.C.-specific TPL-001-5.1 Implementation Plan will not adversely impact the reliability of the BES and will allow a similar level of flexibility to B.C. MRS registered entities as has been afforded to U.S. based registered entities during its implementation.

Therefore, in connection with the recommendation to adopt the TPL-001-5.1 standard, BC Hydro recommends that a B.C.-specific version of the TPL-001-5.1 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards.

3.4 B.C. TPL-007-4 Implementation Plan

In this Report, BC Hydro recommends the adoption of the TPL-007-4 standard. In connection with that recommendation, BC Hydro also recommends a B.C.-specific version of the FERC approved TPL-007-4 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards. BC Hydro has drafted a B.C.-specific version of the TPL-007-4 Implementation Plan to align it with the B.C. MRS program.

The TPL-007-4 reliability standard is a new standard to B.C. and does not supersede any pre-existing reliability standards adopted in B.C. The FERC approved TPL-007-4 Implementation Plan considers that the preceding TPL-007-1, TPL-007-2, and TPL-007-3 standard versions, all held in abeyance in B.C., had been previously adopted in the U.S. Therefore, the B.C. TPL-007-4 Implementation Plan is based on an aggregated timeframe taken from the TPL-007-1, TPL-007-2, TPL-007-3, and TPL-007-4 Implementation Plans developed by NERC so that B.C. MRS-registered entities are given comparable amounts of time to implement the TPL-007-4 reliability standard as afforded to U.S. registered entities. Both clean and redline drafts showing the changes proposed for the B.C.-specific version in relation to the NERC TPL-007-4 Implementation Plan are included in Attachment D-2 to Appendix D for the BCUC's review.

The B.C. specific Implementation Plan provides clarity to entities on implementation times for initial compliance with a subset of requirements per the respective standard. BC Hydro submits that adopting the B.C.-specific TPL-007-4 Implementation Plan will not adversely impact the reliability of the BES and it would allow a similar level of flexibility to B.C. MRS-registered entities that have been afforded to U.S. based registered entities during its implementation.

Therefore, in connection with the recommendation to adopt the TPL-007-4 standard, BC Hydro recommends that a B.C.-specific version of the TPL-007-4 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards.

4 Standards Assessment Process used in the Report

4.1 Identification of Standards for Review and Inclusion in the Report

BC Hydro has assessed the 12 PC Standards and one retired reliability standard identified in Table 2 in accordance with its usual process for standards assessment. This analysis is provided in section 1.1.

As outlined in section 1.1 of the Report, the 12 PC Standards include:

- Entire standards that have been held in abeyance and/or standards that are currently in effect in B.C., but which contain one or more requirements that are related to the PC function that have been held in abeyance by the BCUC under previous orders; and
- Any new FERC-approved standards that relate to the PC function which are being assessed in this report as opposed to Assessment Report No. 14. This includes revisions to currently adopted standards and revisions to standards currently held in abeyance.

A list of all PC Standards and the retired reliability standard is provided in Appendix A-1 and includes a reference to the FERC Order approving them, along with the date of the Order. Appendix A-2 includes clean and red-lined copies of the PC Standards.

4.2 Feedback Sought Through Consultation

BC Hydro consulted with the B.C. MRS registered entities listed below in Table 1 through two rounds of consultation.

Table 1 B.C. MRS Program Registered Entity List

Registered Entities	Registered Entities (Continued)
ARC Resources Ltd. (**ARCR**)	Intercontinental Pulp Mill (**IPML**)
Bear Mountain Wind Limited Partnership (**BMWL**)	Jimmie Creek Limited Partnership (**JCLP**)
British Columbia Hydro and Power Authority (**BCHA**)	Lehigh Cement (**LHC**)
Cape Scott Wind LP (**CSCO**)	Meikle Wind Energy Limited Partnership (**MWEL**)
Capital Power Limited Partnership (**CPLP**)	Northwood Pulp Mill (**NPM**)
Cariboo Pulp & Paper Company (**CPPC**)	Prince George Pulp & Paper Mill (**PGPP**)
Catalyst Paper - Crofton Division (**CPCD**)	Quesnel River Pulp, West Fraser Mills Ltd. (**QUES**)
Catalyst Paper - Port Alberni Division (**CPPAD**)	Rio Tinto Alcan (**RTA**)
Catalyst Paper - Powell River Division (**CPPR**)	Toba Montrose General Partnership (**TMGP**)
Coast Mountain Hydro Limited Partnership (**CMHL**)	Tolko Industries Limited (**TIL**)
Dokie General Partnership (**DGP**)	Upper Lillooet River Power LP (**ULRP**)
Encana (**ENCA**)	V.I. Power Limited Partnership (**VIPL**)
FortisBC Inc. (**FBC**)	WESCUP (**WESC**)
Howe Sound Pulp & Paper Corporation (**HSPP**)	West Fraser Mills Ltd. (**WFM**)
Innergex Renewable Energy Inc. (**CWEI**)	

4.2.1 First Consultation

Each registered entity on the list per Table 1, with the exception of Encana,[12] was originally issued an email package on December 24, 2020.

[12] Attempts were made to contact Encana for the first round of consultation, but their contact information had gone stale. BC Hydro attempted to obtain Encana's contact information from the BCUC; however, the BCUC had the same stale contact information as BC Hydro. Encana was contacted and included in the second round of consultation held on April 30, 2021.

The email package for the first consultation contained instructions and a link to the BC Hydro Reliability Compliance internet website where one survey form (for all of the reliability standards and the retired reliability standard originally being consulted on) was provided for completion by entities (refer to Appendix C-2-A. Entities were asked to complete and return the survey forms to BC Hydro by end of day February 28, 2021. A reminder notice to complete the survey forms was sent to each registered entity on January 12, 2021. On January 13, 2021, BC Hydro held an informational session via teleconference for all registered entities in B.C.

At the time of the first round of consultation, BC Hydro included all reliability standards currently in effect in B.C. that reference the PA or PC functions would be assessed in this Report. This included 24 new standards, two retired reliability standards, and three revised terms.

The entities were asked to provide information for each of the reliability standards being considered as well as the retired reliability standards and certain terms in the Glossary as follows:

(a) Indicate whether there were either no changes to the entity's processes, or state the high-level incremental activities or new activities that needed to be completed to become compliant;

(b) For each incremental or new activity, indicate associated estimated costs in dollar amounts, and identify the assumptions used in developing estimates. The following costs were to be considered:

- Activities where a one-time capital cost will incur; and
- Activities where there are ongoing annual costs associated with compliance; and

(c) Include an assessment of the amount of time reasonably required to come into compliance with the reliability standards and Glossary terms once adopted by the BCUC. The time was to be reflective of any incremental or new activities identified.

The following eight entities responded: (1) BC Hydro; (2) Cape Scott Wind LP; (3) FortisBC Inc.; (4) Innergex Renewable Energy Inc.; (5) Dokie General Partnership; (6) Jimmie Creek Limited Partnership; (7) Toba Montrose General Partnership and (8) Upper Lillooet River Power LP. Dokie General Partnership, Jimmie Creek Limited Partnership, Toba Montrose General Partnership and Upper Lillooet River Power LP provided a single consolidated survey response under the Innergex Renewable Energy Inc. response.

4.2.2 Shift in Assumptions

During the first consultation, BC Hydro sought feedback from entities on the adoption of the standards assuming BC Hydro (as registered entity) would be the PA/PC for BC Hydro's "footprint." BC Hydro's footprint was described as including BC Hydro's own BES assets as well as those BES assets owned by interconnecting entities to BC Hydro who are registered under the BCUC MRS program, with the exception of FortisBC. FortisBC was asked to assume that it would be the PA/PC for its own footprint.

After the first consultation, BC Hydro subsequently changed its assumption to reflect a staged implementation of the PC function for its footprint. In the first stage, BC Hydro would become the PC for its own BES assets. In the second stage, BC Hydro would explore becoming PC entities interconnected to BC Hydro's system who are registered under the BCUC MRS program. In the third stage, BC Hydro would consider being PC for FortisBC. These assumptions were for the purpose of assessing the PC Standards only and do not reflect any determinations about which entities are required to register for the PC function in B.C.

In addition, BC Hydro determined that in the first consultation it had, in error, sought to re-assess reliability standards that referenced the PA/PC function that were already adopted and effective in B.C. As a result, the list of standards being assessed hereunder was revised to reflect only the PC Standards.

BC Hydro also missed the following items in its original package issued for assessment in the first consultation:

- The NERC Glossary Term Geomagnetic Disturbance Vulnerability Assessment previously held in abeyance in B.C. This Glossary Term is associated with the TPL-007-4 standard being assessed in this Report as it contains requirements with sole PC dependencies;
- The PRC-023-2 standard which is adopted and currently effective in B.C. but contains requirements (Requirements R1 – R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6 and Requirement R6) with sole PC dependencies that are currently held in abeyance;
- The TPL-001-4 standard which is adopted and currently effective in B.C. but for which Requirement R7 has sole PC dependencies that are currently held in abeyance.[13]

Finally, it also came to BC Hydro's attention that it had mischaracterized the proposed retirement of the EOP-003-2 reliability standard in its initial communication to the 28 registered entities. This standard was previously held in abeyance in B.C. and hence cannot be retired as it was never adopted.[14]

In light of the changed assumption and the need to consult on the revised list of PC Standards and PC Terms, BC Hydro engaged in a second round of consultations

13 TPL-001-4 is being replaced by TPL-001-5.1; however, TPL-001-4 R7 is being recommended for adoption with an effective date prior to the recommended effective date of TPL-001-5.1.

14 See section 3.2 for a discussion of the EOP-003-2 standard.

with MRS registered entities. As a result, the revised scope included 12 new standards, one retired standard and four revised terms.

4.2.3 Second Consultation

Each registered entity on the list per Table 1 was issued an email package on April 30, 2021 advising that a revised list of 12 PC Standards, one retired reliability standard, and four PC Terms would now be assessed in the Report.

The email packages contained instructions and a link to the BC Hydro Reliability Compliance internet website where one survey form (for PC Standards, the retired reliability standard, and PC Terms) was provided for completion by entities(refer to Appendix C-2-B. Entities were asked to complete and return the survey forms to BC Hydro by end of day May 14, 2021. On May 5, 2021, BC Hydro held an informational session via teleconference for all registered entities in B.C. explaining the changes that led to the second consultation.

The entities were given the option to either instruct BC Hydro to maintain their survey forms from the first consultation and indicate no additional feedback, or to submit feedback via the new survey form which would completely replace feedback provided under the first round of consultation.

The entities were asked to provide information for each PC Standard, retired reliability standard and PC Term as follows:

(a) Indicate whether there were either no changes to the entity's processes, or state the high-level incremental activities or new activities that needed to be completed to become compliant;

(b) For each incremental or new activity, indicate associated estimated costs in dollar amounts, and identify the assumptions used in developing estimates. The following costs were to be considered:

- Activities where one-time costs will incur to meet initial compliance; and

- Activities where there are ongoing annual costs associated with compliance; and

(c) Include an assessment of the amount of time reasonably required to come into compliance with the PC Standards and PC Terms once adopted by the BCUC. The time was to be reflective of any incremental or new activities identified.

The following seven entities responded: (1) BC Hydro; (2) FortisBC Inc.; (3) Innergex Renewable Energy Inc.; (4) Dokie General Partnership; (5) Jimmie Creek Limited Partnership; (6) Toba Montrose General Partnership and (7) Upper Lillooet River Power LP.

Dokie General Partnership, Jimmie Creek Limited Partnership, Toba Montrose General Partnership and Upper Lillooet River Power LP provided a single consolidated survey response under the Innergex Renewable Energy Inc. response and instructed BC Hydro to maintain their survey forms submitted during the first consultation. FortisBC Inc. also instructed BC Hydro to maintain its survey forms submitted during the first consultation. Cape Scott Wind, who responded to the first consultation, did not respond to the second consultation. Accordingly, their first consultation survey forms have been maintained. BC Hydro’s responses (as a registered entity) are provided in full in Appendix C-1 and registered entities’ responses are provided in full in Appendix C-3.

5 Assessment of Individual Standards

5.1 PC Standards

BC Hydro is recommending the adoption of 11 out of the 12 PC Standards, as well as the retirement of one reliability standard[15]. BC Hydro is not recommending the adoption of the EOP-003-2 PC Standard, for the reasons discussed in section 3.2.

The 11 PC Standards being recommended for adoption in B.C. would entirely supersede 12[16] reliability standards adopted in B.C. by Order Nos. G-67-09, R-1-13, R-38-15, and R-27-18A.

BC Hydro has concluded that the 11 PC Standards will preserve or enhance the reliability of the BES in B.C., and thus are in the public interest and are suitable for adoption in B.C. BC Hydro has also concluded there are no adverse impacts to the reliability of the BES from the retirement of the one retired reliability standard in B.C.

BC Hydro has assessed the estimated incremental one-time and ongoing annual costs of achieving and maintaining compliance with the 12 PC Standards. . Consistent with the approach taken in previous MRS assessment reports, BC Hydro sought input from all B.C. MRS registered entities regarding their estimated incremental one-time and annual ongoing costs associated with achieving and maintaining compliance with the PC Standards.

A complete list of the registered entities with whom BC Hydro consulted is provided in Table 1, section 4.2. However, given the revised key assumptions as described in section 4.2 that there could be two entities carrying out the PA/PC functions in B.C. with (1) BC Hydro as the PA/PC for its owned BES assets initially; and (2) FortisBC Inc. as the PA/PC for its owned BES assets, the feedback assessed under this Report is now limited to that of BC Hydro and FortisBC Inc. only. This is because

15 Reference to the FAC-013-1 reliability standard currently effective in B.C.

16 Refer to Appendix A-1 for a list of BCUC approved reliability standards that would be superseded by reliability standards assessed in the Report.

BC Hydro anticipates that the other registered entities will not be required to have a PC in the near term and that the impacts of those entities becoming mapped to a PC will be reconsidered at that time. Nonetheless, registered entities' responses are reproduced in full in Appendix C-3.

BC Hydro's registered entity feedback is reproduced in full in Appendix C-1 of the Report and the feedback from FortisBC Inc. is provided in Table 3, section 5.4.

On the basis of BC Hydro's own assessment and the responses received from FortisBC, the cumulative cost for BC Hydro and FortisBC to achieve and maintain compliance with the 11 PC Standards and four PC Terms being recommended for adoption in B.C. is estimated to be a minimum of $4,784,000 with respect to one-time costs, and a minimum of $469,000 on an annual ongoing basis. With respect to the costs considered herein, BC Hydro is of the view that these expenditures are necessary, given that the major portion of costs incurred relate to the:

- Development and implementation of organizational changes to implement the PA/PC function;
- Development of processes and procedures for new steady-state, dynamic, and short circuit data modeling and reporting requirements, including verification of data sources and the development and maintenance of data management systems.
- Development of RAS study plans and periodic evaluation of RAS to determine if they are performing as designed and to identify deficiencies for communication to applicable functional entities;
- Development and implementation of processes to perform assessments of angular stability and power swing conditions, review of protection relays which may trip during power swings, and to develop and implement corrective action plans;

- Updates to protection systems as part of corrective action plans pursuant to new transmission planning study requirements and additional assessments related to the identification of potential Non-Consequential Load Loss; and
- Development and implementation of new periodic Geomagnetic Vulnerability Assessments and associated corrective action plans related to power transformers, including the design and installation of equipment to monitor geomagnetically-induced currents.

The remaining costs are largely associated with the development of new or revisions to existing process and procedure documentation.

BC Hydro has assessed the 11 PC Standards and one retired reliability standard against the criteria set out in section 125.2(3) of the UCA. The PC Terms are discussed in section 5.3 below.

- Section 5.2 summarizes BC Hydro's approach to addressing these criteria;
- Section 5.3 provides a description of each of the 12 PC Standards and the one retired standard and an explanation of the reliability, suitability and applicability issues, along with BC Hydro's conclusions; and
- Section 1.1 addresses the cost assessment and summarizes BC Hydro's final assessment of each of the 12 PC Standards and the one retired standard.

5.2 Analytical Approach to Assessment of Reliability Impact, Suitability, Cost of Adoption and Application

The analytical approach taken to evaluate the PC Standards identified in the Report against the legislated assessment criteria is consistent with that used in the annual MRS assessment reports. Compliance-related provisions included in the reliability standards are not applicable to the meaning of "reliability standards" defined in section 125.2 of the UCA. As a result, BC Hydro does not assess these compliance-related provisions in the Report. To indicate that BC Hydro does not assess this part of the reliability standards, the compliance-related provisions have been struck-through in the clean and redline versions of each PC Standard included in Appendix A-2. Nevertheless, BC Hydro recognizes that the compliance-related provisions may be adopted by the BCUC.

BC Hydro submits that the effective dates stated in the PC Standards are not applicable in B.C. Accordingly, a strike-through of section A.5 – Effective Date – is included in the clean and redlined versions of each reliability standard included in Appendix A-2.

5.2.1 Analytical Approach in Assessing Adverse Reliability Impacts

BC Hydro has used the same approach in assessing adverse reliability impacts that is consistent with the annual MRS assessment reports. This approach relies on a determination that those reliability standards that have either: (i) performance requirements that are not currently employed in B.C., or (ii) requirements as stringent, or more stringent than requirements or practices currently employed in B.C. will, by definition, have neutral or positive impacts on the reliability of the BES in B.C. Consequently, BC Hydro's approach is to identify performance requirements associated with new, or revisions to, reliability standards that are less stringent than the existing reliability standards already adopted in B.C., or practices otherwise mandated in utility tariffs or business practices approved or endorsed by the BCUC.

5.2.2 Analytical Approach for the Suitability Assessment

The Report uses the same criteria to assess the PC Standards and the retired standard that were developed for the annual MRS assessment reports. The two criteria used for this analysis are set out below:

(a) "Administrative Suitability" means that the requirements in the reliability standard are fit and appropriate for implementation in light of the policy and regulatory framework in B.C. The requirements can be implemented without requiring the ongoing involvement of NERC, the U.S. Government, or other extra-jurisdictional entities in such a manner as would impair the operation and enforcement of the requirement in B.C. If one or more of the requirements in the reliability standard incorporate by reference reliability standards not yet adopted in other jurisdictions, the remaining requirements in the reliability standard can still be implemented presently in B.C. without giving effect to the particular requirement(s) containing the cross reference; and

(b) "Technical Suitability" means that the requirements in the reliability standard are fit and appropriate for implementation in B.C., taking into consideration the unique geographical, structural, design, and functional aspects of the B.C. BES and the assets that support the reliable operation of this system.

5.2.3 Analytical Approach for the Cost Assessment

BC Hydro's approach to assessing the potential costs of the PC Standards in the Report is consistent with the approach used to assess reliability standards in the annual MRS assessment reports. The objective is to provide a conceptual estimate of the minimum expected costs of adopting reliability standards in B.C. sufficient to inform the BCUC's public interest assessment. Accordingly, only the costs that BC Hydro and FortisBC Inc. will potentially incur to achieve and maintain full compliance with the PC Standards were assessed. Any costs associated with B.C. entities attaining or maintaining compliance with pre-existing reliability standards in B.C. were excluded.

5.2.4 Analytical Approach for the Application of the Reliability Standards

Regarding the criterion contained in paragraph 125.2(3)(c.1) of the UCA, BC Hydro's approach to assess the application of the PC Standards and the retired standard to persons or persons in respect of specified equipment in the Report is consistent with the approach used to review reliability standards in the annual MRS assessment reports.

BC Hydro assesses the Applicability section contained in the Introduction of the relevant standard at section A.4, to ensure consistency with the functional registration categories contained in the B.C. MRS program, as contained in the MRS Rules of Procedure in B.C. BC Hydro considers this approach to satisfy the criterion contained in paragraph 125.2(3)(c.1) of the UCA.

Any issues regarding the applicability of reliability standards to particular entities can be addressed in the context of the BCUC's registration and compliance regime.

5.3 Initial Screening of the Standards for Adverse Reliability Impacts and Suitability

In terms of the assessment of the PC Standards and the retired standard against the reliability and suitability criteria, BC Hydro first performed an initial screening against the criteria described in section 5.2 to identify issues for further examination. This initial screening does not purport to be BC Hydro's final assessment.

The results of BC Hydro's initial screening of the PC Standards and the retired standard for potential issues regarding adverse reliability impacts and suitability are summarized below in Table 2, which includes:

- The "Standard" column, which identifies the PC Standards or the retired standard assessed;
- The "Changed from BCUC Approved Standard" column, which identifies whether the PC Standard is a revision to a reliability standard already adopted by the BCUC;
- The "Adverse Impact" column, which identifies potential issues relating to adverse reliability impact;
- The "Suitability Issues" columns, which identify potential suitability issues:
    - "Requires NERC Approval/Participation": Identifies a potential Technical or Administrative Suitability issue as related to continued reliance on approvals

by NERC and/or participation by NERC to implement the requirements of a given reliability standard;

- "Requires Provisions of Information to NERC or the WECC": Identifies a potential Technical or Administrative Suitability issue that requires ongoing reporting of information to NERC or WECC (i.e., lack of clarity on reporting instructions, references to undefined processes or reporting tools, etc.);
- "Refers to Standard not yet FERC Approved": Identifies a potential Technical or Administrative Suitability issue with a PC Standard as it contains one or more references to other reliability standards that have not yet been approved by FERC in the U.S., and thereby not assessed for adoption in B.C., which would affect the ability to implement one or more requirements of the PC Standard; and

"Other Suitability Issues": Identifies whether there are any other Administrative Suitability, Technical Suitability or reliability standard Applicability issues identified, apart from the categories already defined, that would affect the ability to implement the requirements of the PC Standard.

Table 2 Initial Screening of PC Standards and the Retired Standard for Adverse Reliability Impact and Suitability

No.	Standard	Changed from BCUC Approved Standard or Standard Held in Abeyance	Adverse Impact	Suitability Issues				
				Requires NERC Approval/ Participation	Requires Provisions of Information to NERC or WECC		Refers to Standard not yet FERC Approved	Other Suitability/ Applicability Issues
					To NERC	To WECC		
1	EOP-003-2	Yes (previously held in abeyance and revision to EOP-003-1 adopted in B.C.)[9]	No	No	No	No	No	No
2	MOD-032-1	No (previously in abeyance)[9]	No	No	No	No	No	Yes
3	MOD-033-2	Yes (revision to MOD-033-1 in abeyance)[7]	No	No	No	No	No	Yes
4	PRC-006-4	Yes (revision to PRC-006-3 in abeyance)[7]	No	No	No	No	No	No
5	PRC-010-2	Yes (previously held in abeyance and revision to PRC-010-0 adopted in B.C.)[9]	No	No	No	No	No	No
6	PRC-012-2 Requirements R1: Attachment 1, Section II Parts 6(d) and 6(e) R2: Attachment 2, Section I Parts 7(d) and 7(e), and R4	No (subset of requirements in abeyance)[8]	No	No	No	No	No	No

No.	Standard	Changed from BCUC Approved Standard or Standard Held in Abeyance	Adverse Impact	Suitability Issues				
				Requires NERC Approval/ Participation	Requires Provisions of Information to NERC or WECC		Refers to Standard not yet FERC Approved	Other Suitability/ Applicability Issues
					To NERC	To WECC		
7	PRC-023-2 Requirements R1 – R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6 and R6	No (subset of requirements in abeyance)[8]	No	No	No	No	No	No
8	PRC-023-4 Requirements R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6	No (subset of requirements in abeyance)[8]	No	No	No	Yes[17]	No	No
9	PRC-026-1	No (previously held in abeyance) [9]	No	No	No	No	No	No
10	TPL-001-4 Requirement R7	No (subset of requirements in abeyance)[8]	No	No	No	No	No	No

[17] PRC-023-4 Requirement 5 requires entities to report events, Demand and energy data, Mis-operation incident reports, and updated lists of circuits meeting specific relay setting criterion, respectively to WECC as the Regional Entity in B.C. However, there are no perceived suitability issues that would impact a B.C. entity's ability to comply with the identified reliability standard requirements given that WECC has a compliance administration agreement in place with the BCUC under the BCUC MRS program.

No.	Standard	Changed from BCUC Approved Standard or Standard Held in Abeyance	Adverse Impact	Suitability Issues				
				Requires NERC Approval/ Participation	Requires Provisions of Information to NERC or WECC		Refers to Standard not yet FERC Approved	Other Suitability/ Applicability Issues
					To NERC	To WECC		
11	TPL-001-5.1	Yes (revision to TPL-001-4 adopted in B.C. which has a requirement in abeyance)[7,8]	No	No	No	Yes[18]	No	Yes[19]
12	TPL-007-4	Yes (revision to TPL-007-3 in abeyance)[7]	No	No	No	Yes[20]	No	No
13	FAC-013-1/2	Retired[21]	No	No	No	No	No	No

18 PC Standard TPL-001-5.1 Attachment 1 section III is referenced from requirements to provide information to the ERO and obtain approvals from the ERO. In the U.S., NERC has been established to be the ERO, however in B.C., there is no such ERO established. There is no compliance obligation in B.C. to follow NERC's processes, provide information to NERC, or obtain approvals from NERC; any adherence pertaining to the ERO for a given requirement is strictly voluntary and is of no force or effect in B.C. Therefore, there is no perceived suitability issue that would impact a B.C. entity's ability to comply with the identified reliability standard requirements.

19 Requirement 1 of TPL-001-5.1 requires the maintenance of System models that shall use data consistent with that provided per the referenced MOD-032 reliability standard for performing studies needed to complete Planning Assessments. The MOD-032 reliability standard is held in abeyance in B.C. due to PC dependencies but is being concurrently reassessed per this Report. Until the MOD-032 reliability standard is adopted and effective in B.C., the TPL-001-5.1 PC Standard cannot be made effective even if adopted by the BCUC.

20 Requirements D.A.7.5. and D.A.11.5. of TPL-007-4 require applicable entities to submit a revised Corrective Action Plan (CAP) to either the Compliance Enforcement Authority (CEA; WECC) or Applicable Governmental Authority (the BCUC) when revised within 90 calendar days of revision. These submissions can be subject to comments from either WECC or the BCUC depending on to whom the CAP was submitted to and to which received comments must be responded to within specified timeframes. However, there are no perceived suitability issues that would impact a B.C. entity's ability to comply with the identified reliability standard requirements given that WECC has a compliance administration agreement in place with the BCUC under the BCUC MRS program.

21 FAC-013-2 is currently in abeyance which supersede FAC-013-1 which is currently adopted and effective in B.C. As described in section 2.1, FAC-013-1 is being recommended for accelerated retirement as the FAC-013-2 standards has been retired in the U.S. See section 3.1 for details.

5.4 Summary of Final Assessment of the Standards Assessed in the Report

BC Hydro's final assessment, based on responses from B.C. registered entities, including BC Hydro, is summarized below in Table 3, which includes:

- BC Hydro's final assessment as to whether the adoption of the 12 PC Standards or retirement of the one retired standard will give rise to adverse reliability consequences;[22]
- BC Hydro's final assessment as to the suitability of the 12 PC Standards, based on the criteria described in section 5.2.2;
- BC Hydro's and FortisBC Inc.'s estimated incremental one-time and ongoing annual costs to achieve and maintain compliance; and
- BC Hydro's recommended effective dates, based on comments made by registered entities who responded to the stakeholder survey. BC Hydro recommends that these recommended effective dates be adopted by the BCUC to replace section A.5-Effective Date in each of the PC Standards. For informational purposes only, feedback that does not align with BC Hydro's recommended effective dates are listed under 'Feedback Exceptions' where applicable.

BC Hydro's final assessment as to the application of the PC Standards is included as a separate paragraph at the end of section 1.1.

[22] No adverse reliability consequences were identified during the final assessment.

Table 3 Final Assessment Summary of PC Standards and the Retired Standard

Standard	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/Year)	Recommended Effective Date
N/A – Across all PC Standards in this Table 3	N/A	**BC Hydro –** $40,000; one-time internal training and organizational change management costs pertaining to the PC function.	None reported.	N/A
EOP-003-2	None reported.	**FortisBC -** **R2:** This standard has been inactive or retired in the U.S. since March 31, 2017. The previous revision to this standard (EOP-003-1) has been expired or retired in BC since September 30, 2018. Therefore, FortisBC recommends that this standard be retired in B.C..[23]	None reported.	**BC Hydro's Consolidated Recommendation:** Not recommended for adoption in B.C.[24] **Feedback Exceptions:** **Fortis BC Inc. -** Recommended retirement date immediately after BCUC approval.[23]
FAC-013-2	None reported.	None reported.	None reported.	**BC Hydro's Consolidated Recommendation:** Not recommended for adoption in BC. Instead, recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.[25] **Feedback Exceptions:** **Fortis BC Inc. -** Recommended retirement date immediately after BCUC approval.[26]
MOD-032-1	None reported.	**BC Hydro -** **R1:** $25,000; BC Hydro will need to develop process and procedures for the new data and reporting requirements. **R2:** $500,000; BC Hydro will need to verify data sources and develop and maintain data management systems. **Fortis BC Inc. -** **R1-R4:** $5,000 to $10,000; FortisBC will need to develop new steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for use in developing models within the FortisBC BES footprint.	**BC Hydro -** **R2:** $40,000; BC Hydro will need to verify data sources and maintain data management systems.	**BC Hydro's Consolidated Recommendation:** **R1:** The first day of the first calendar quarter that is 12 months after BCUC adoption. **R2 - R4:** The first day of the first calendar quarter that is 24 months after BCUC adoption. **Feedback Exceptions:** **Fortis BC Inc. -** Recommended effective date is 24 to 36 months after BCUC approval.

[23] BC Hydro does not agree with FortisBC regarding the status of EOP-003-1 in B.C. The EOP-003-1 reliability standard remains effective in B.C. (since November 1, 2010 per BCUC Order No. G-67-09) and has not been retired. EOP-003-1 will only be superseded pending adoption of the EOP-003-2 reliability standard or alternatively, adoption of the PRC-010-2 reliability standard, which in turn supersedes EOP-003-2 in conjunction with the currently effective EOP-011-1 reliability standard. BC Hydro also notes that as the EOP-003-2 reliability standard is held in abeyance in B.C. and not actually adopted, it cannot be retired. BC Hydro instead does not recommend the EOP-003-2 standard for adoption in B.C. See section 3.2 Non-adoption of the EOP-003-2 Standard.

[24] The EOP-003-2 reliability standard will be completely superseded with the adoption of the PRC-010-2 reliability standard, which is recommended for adoption under this Report, in conjunction with the currently effective EOP-011-1 reliability standard. See section 3.2.

[25] FAC-013-2 was retired in the U.S. as of December 14, 2020 per FERC Order No. 873. See section 2.1.

[26] The FAC-013-2 reliability standard is held in abeyance in B.C. and as such, it cannot be retired. In light of the FAC-013-2 retirement in the U.S. however, BC Hydro does not recommend the adoption of FAC-013-2 and is recommending the accelerated retirement of the preceding FAC-013-1 reliability standard currently in effect in B.C. See section 3.1.

Standard	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/Year)	Recommended Effective Date
MOD-033-2	None reported.	**BC Hydro -** **R1:** $140,000; BC Hydro will need to develop and implement internal procedures to meet the requirement. **R2:** $32,000; BC Hydro will need to develop and implement internal procedures to meet the requirement. **Fortis BC Inc. -** **R1, R2:** $40,000 to $70,000; FortisBC will need to implement a documented data validation process and complete a comparison of the performance of the FortisBC BES footprint system model to actual system behavior at least once every 24 calendar months through simulation.	**BC Hydro -** **R1:** $40,000; BC Hydro will need to implement internal procedures to meet the requirement. **R2:** $10,000; BC Hydro will need to develop and implement internal procedures to meet the requirement. **Fortis BC Inc. -** **R1:** $40,000 to $70,000; ongoing costs are required every 24 calendar months.	The first day of the first calendar quarter, 36 months after BCUC adoption. Initial Performance of Periodic Requirements: MOD-033-2, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the effective date of MOD-033-2.
PRC-006-4	None reported.	**BC Hydro –** **D.B.1, D.B.3, R9, R10, D.B.11, D.B.12, D.B.14:** $1,530,000; costs are for BC Hydro to participate in WECC meetings, review reports and run studies for initial compliance. BC Hydro may need to modify its UFLS program. As part of determining if modifications to BC Hydro's UFLS program are required, BC Hydro will need to assess how entities forming part of BC Hydro's UFLS program will need to participate. The mitigation or capital projects may include entities forming part of BC Hydro's UFLS program registering under MRS, BC Hydro or other entities modifying equipment, and/or BC Hydro taking ownership, operations and/or control of some equipment currently owned, operated and/or controlled by other entities. Unable to assess the one-time incremental costs required to mitigate issues and/or implement capital projects at this time as these are dependent on the results of the WECC meetings, study results, and discussions with entities forming part of BC Hydro's UFLS program. **R6:** $20,000; BC Hydro will need to develop processes and procedures. **R15:** BC Hydro may need to develop mitigation or capital projects related to entities forming part of BC Hydro's UFLS program depending on the results of assessments under other requirements (e.g., D.B.4 or D.B.12). Unable to assess the one-time incremental costs to mitigate issues and/or implement capital projects at this time.	**BC Hydro -** **D.B.1, D.B.3, R9, R10, D.B.11, D.B.12, D.B.14:** $30,000; costs are for BC Hydro to participate in WECC meetings, studies, and discussions with entities forming part of BC Hydro's UFLS program. BC Hydro is unable to assess the ongoing incremental costs to mitigate issues and/or implement capital projects at this time as these are dependent on the results of the studies and discussions with the entities forming part of BC Hydro's UFLS program. **R6:** $5,000; BC Hydro maintain and implement processes and procedures. **R15:** $5,000; BC Hydro may need to develop mitigation or capital projects related to entities forming part of BC Hydro's UFLS program depending on the results of assessments under other requirements (e.g., D.B.4 or D.B.12). Unable to assess the ongoing incremental costs to mitigate issues and/or implement capital projects at this time.	**BC Hydro's Consolidated Recommendation:** The first day of the first calendar quarter, 36 months after BCUC adoption. **Feedback Exceptions:** **Fortis BC Inc. -** Recommended effective date immediately after BCUC approval.

Standard	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/Year)	Recommended Effective Date
PRC-010-2	None reported.	None reported.	**BC Hydro -** **R1:** $10,000; BC Hydro currently does not have an applicable UVLS and therefore currently does not have a UVLS Program. BC Hydro will need to evaluate the effectiveness of its UVLS Program if it needs to develop one as a PC and provide the UVLS Program's specifications and implementation schedule.	**BC Hydro's Consolidated Recommendation:** The first day of the first calendar quarter, three months after BCUC adoption. **Feedback Exceptions:** **Fortis BC Inc. -** Recommended effective date immediately after BCUC approval.
PRC-012-2 Requirements R1: Attachment 1, Section II Parts 6(d) and 6(e) R2: Attachment 2, Section I Parts 7(d) and 7(e), and R4	None reported.	**BC Hydro -** **R1:** $15,000; BC Hydro will need to develop processes and procedures. **R4:** $507,000; BC Hydro will need to develop study plan, undertake RAS evaluation study and update processes and complete studies for initial compliance. **Fortis BC Inc. -** **R4:** $0; FortisBC will need to perform an evaluation of each RAS within its BES footprint at least once every five calendar years. The majority of this work is completed in each annual planning assessment, so only minor documentation updates are required for compliance with this standard.	**BC Hydro -** **R4:** $107,000; BC Hydro will need to undertake RAS evaluation studies.	**BC Hydro's Consolidated Recommendation:** No change to the October 1, 2021 PRC-012-2 effective date in B.C. and B.C. specific PRC-012-2 Implementation Plan adopted per BCUC Order No. R-33-18 with the following exceptions pending BCUC approval. **R1 Attachment 1, Section II Parts 6(d) and 6(e)** and **R2 Attachment 2, Section I Parts 7(d) and 7(e)**: Pending BCUC adoption of these requirements, align with the October 1, 2021 effective date of PRC-012-2 in B.C. **R4:** Pending BCUC adoption of this requirement, align with the FERC approved NERC PRC-012-2 implementation plan as follows: For existing RAS, initial performance of obligations under Requirement R4 must be completed within five (5) full calendar years after the October 1, 2021 effective date of PRC-012-2 in B.C. For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within five (5) full calendar years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3. **Feedback Exceptions:** **Fortis BC Inc. -** **R4:** Recommended effective date is 24 to 36 months after BCUC approval.
PRC-023-2 Requirements R1 – R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6 and R6	None reported.	**BC Hydro -** **R1-R5:** For circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6, BC Hydro is unable to assess the one time incremental costs at this time as this is dependent on the results of assessments/studies pursuant to R6. **R6:** Shared costs with PRC-023-4 R6.	**BC Hydro -** **R1-R5:** For circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6, BC Hydro is unable to assess the ongoing incremental costs at this time as this is dependent on the results of assessments/studies pursuant to R6. **R6:** Shared costs with PRC-023-4 R6.	No change to existing PRC-023-2 effective dates in B.C. with the following exception pending BCUC approval. **R1-R6 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1:** Align with implementation timeframe of PRC-023-4 Requirements R1 – R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6 pending BCUC adoption.

Standard	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/Year)	Recommended Effective Date
PRC-023-4 Requirements R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6	None reported.	**BC Hydro -** **R1, R2, R4, R5:** Depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one-time incremental costs at this time as this is dependent on the results of assessments/studies pursuant to R6. **R3:** $15,000; BC Hydro will need to develop methodology to evaluate the calculated circuit capability as Facility Rating and update internal process. In addition, depending on R6 assessment results, there may be additional cost incurred regarding application of settings to additional circuits identified, however it is not possible to estimate one-time incremental cost at this time until the study is performed. **R6:** $39,000 (shared with PRC-023-2 R6); BC Hydro will need to develop process and conduct annual assessment. BC Hydro may also need to address the impact to other RC related standards including IRO-002, IRO-008, IRO-010, PRC-012, PRC-015, FAC-008 due to the addition of PC function, however it is not possible to estimate all costs at this time until R6 assessments are performed. **Fortis BC Inc. -** **R6:** $5,000 to $10,000; FortisBC would need to conduct an assessment at least once each calendar year, with no more than 15 months between assessments, to determine the 100 kV to 200 kV circuits in its BES footprint which must comply with the PRC-023-4 load ability requirements. FortisBC 100 kV to 200 kV circuits would need to comply with this standard if they meet the required criteria.	**BC Hydro -** **R1, R2, R4, R5:** Depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the ongoing incremental costs at this time as this is dependent on the results of assessments/studies pursuant to R6. **R3:** $5,000; BC Hydro will need to implement methodology to evaluate the calculated circuit capability as Facility Rating. In addition, depending on R6 assessment results, there may be additional cost incurred regarding application of settings to additional circuits identified, however it is not possible to estimate ongoing incremental cost at this time until the study is performed. assessments/studies pursuant to R6. **R6:** $6,000; PC will need to conduct annual assessments of circuits and communicate this listing to applicable entities. Depending on the assessment result of R6, there may be additional cost incurred however it is not possible to estimate cost at this time until R6 assessments are performed. **Fortis BC Inc. -** **R6:** $5,000 to $10,000; FortisBC would need to conduct an assessment at least once each calendar year, with no more than 15 months between assessments, to determine the 100kV-200kV circuits in its BES footprint which must comply with the PRC-023-4 load ability requirements. FortisBC 100 kV to 200 kV circuits would need to comply with this standard if they meet the required criteria.	**BC Hydro's Consolidated Recommendation:** No change to existing PRC-023-4 effective dates in B.C. with the following exception pending BCUC approval. **R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6, and for R6:** The first day of the first calendar quarter, 24 months after BCUC adoption. **Feedback Exceptions:** **BC Hydro -** No change to existing effective dates in B.C. with the following exception. **R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6:** The first day of the first calendar quarter, 12 months after BCUC approval. **Fortis BC Inc. -** Recommended effective date is 24 to 36 months after BCUC approval.

Standard	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/Year)	Recommended Effective Date
PRC-026-1	None reported.	**BC Hydro -** **R1:** $75,000; BC Hydro will need to develop and implement process to perform assessment of power swing conditions. **R2:** $300,000; BC Hydro will need to review protection relays which may trip during power swings. **R3, R4:** Unable to assess the one-time incremental costs required to develop and implement corrective action plans (**CAPs**) at this time as this is dependent on the results of assessments/studies. **Fortis BC Inc. -** **R1:** $10,000 to $20,000; FortisBC would need to complete an angular stability and power swing study document at least once each calendar year. FortisBC does not have any separate registered GO and TO entities in its BES footprint. FortisBC does not expect to have any elements that would need to comply with this standard.	**BC Hydro -** **R1:** $5,000; BC Hydro will need to implement process to perform assessment of power swing conditions. **R2:** $15,000; BC Hydro will need to review protection relays which may trip during power swings. **R3, R4:** Unable to assess the ongoing incremental costs required to develop and implement CAPs at this time as this is dependent on the results of assessments/studies. **Fortis BC Inc. -** **R1:** $10,000 to $20,000; FortisBC would need to complete an angular stability and power swing study document at least once each calendar year.	**BC Hydro's Consolidated Recommendation:** **R1:** The first day of the first full calendar year, 12 months after BCUC adoption. **R2 - R4:** The first day of the first full calendar year, 36 months after BCUC adoption. **Feedback Exceptions:** **Fortis BC Inc. -** Recommended effective date is 24 to 36 months after BCUC approval.
TPL-001-4 Requirement 7	None reported	BC Hydro – **R7:** $5,000; BC Hydro will need to develop documentation and processes.	None reported	No change to existing TPL-001-4 effective dates in B.C. with the following exception pending BCUC approval. **R7:** The first day of the first calendar quarter, three months after BCUC adoption.
TPL-001-5.1	**BC Hydro -** Requires adoption of the MOD-032-1 reliability standard held in abeyance in B.C. but being recommended for adoption in B.C. per this Report.	**BC Hydro -** **R4:** $40,000; BC Hydro may need to update protection systems as part of corrective action plans (**CAPs**) pursuant to studies performed to meet the requirement. Unable to assess all one-time incremental costs required to develop and implement CAPs at this time as this is dependent on the results of studies.	**BC Hydro -** **R2:** $60,000; BC Hydro will need to undertake additional assessment related to NCLL. **R4:** $30,000; BC Hydro may need to update protection systems as part of CAPs pursuant to studies performed to meet the requirement. Unable to assess all ongoing incremental costs required to develop and implement CAPs at this time as this is dependent on the results of studies.	**BC Hydro's Consolidated Recommendation:** The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C. specific TPL-001-5.1 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards. Please refer to section 3.3 of the Report. **Feedback Exceptions:** **Fortis BC Inc. -** Recommended effective date immediately after BCUC approval.

Standard	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/Year)	Recommended Effective Date
TPL-007-4	None reported.	**BC Hydro -** **R1:** $10,000; BC Hydro will need to develop process to meet the requirement. **R3:** $10,000; BC Hydro will need to develop criteria to meet the requirement. **R4:** $73,000; BC Hydro will need to develop process and complete benchmark GMD Vulnerability assessment. **R6:** $100,000; BC Hydro will need to conduct benchmark thermal impact assessments. **R7(R7.1, R7.2), D.A.7.3-D.A.7.5, D.A.11.3-D.A.11.5:** $220,000; BC Hydro will need to develop and implement Corrective Action Plans (**CAPs**). Unable to assess all the one-time incremental costs required to mitigate issues and/or implement CAPs at this time as this is dependent on the results of the GMD Vulnerability Assessments. **R8:** $40,000; BC Hydro will need to undertake supplemental study. **R12:** $1,020,000; BC Hydro will need to develop and implement a process to obtain GIC data, including design, procurement, and installation of equipment to monitor GIC data. **R13:** $8,000; BC Hydro will need to implement a process to obtain geomagnetic field data.	**BC Hydro -** **R4:** $11,000; BC Hydro will need to implement periodic benchmark GMD Vulnerability Assessments. **R6:** $10,000; BC Hydro to conduct periodic benchmark thermal impact assessments. **R7(R7.1, R7.2), D.A.7.3-D.A.7.5, D.A.11.3-D.A.11.5:** $5,000; BC Hydro will need to develop and implement CAPs. Unable to assess all the ongoing incremental costs required to mitigate issues and/or implement CAPs at this time as this is dependent on the results of the GMD Vulnerability Assessments. **R8:** $10,000; BC Hydro will need to periodically complete supplemental GMD Vulnerability Assessments. **R12:** $5,000; BC Hydro will need to obtain monitored GIC data on an ongoing basis. **R13:** $5,000; BC Hydro will need to implement a process to obtain geomagnetic field data. **Fortis BC Inc. -** **R4:** $20,000 to $40,000; Ongoing costs are required every 60 calendar months. FortisBC will need to confirm the WECC GMD Vulnerability Assessments study results on an ongoing basis.	**BC Hydro's Consolidated Recommendation:** The first day of the first calendar quarter, six months after BCUC adoption. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C. specific TPL-007-4 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards. Please refer to section 3.4 of the Report. **Feedback Exceptions:** **Fortis BC Inc. -** Recommended effective date is 24 to 36 months after BCUC approval.

BC Hydro's assessment is that 11 out of the 12 PC Standards and the one retired standard should be recommended to the BCUC for adoption and retirement, respectively, in B.C. as they will either maintain or enhance the reliability of the BES in B.C.

The total cumulative cost required to adopt the recommended eleven PC Standards in B.C. is estimated to be a minimum of $4,784,000 for their implementation, with ongoing annual costs of a minimum of $469,000 to maintain compliance. The cost estimates are the cumulative costs provided by both BC Hydro and FortisBC Inc. as the two prospective PA/PC functional entities for their respective owned BES assets.

- BC Hydro reported estimated incremental one-time costs of at least $4,764,000. Annual ongoing costs are estimated to be at least $414,000,[27] and
- FortisBC Inc. reported estimated incremental one-time costs of at least $60,000. Annual ongoing costs are estimated to be at least $55,000.

BC Hydro's final assessment as to the Application of the PC Standards is to recommend that section A.4 Applicability in the PC Standards be adopted by the BCUC.

6 NERC Glossary of Terms

This section outlines the Revised Terms assessed in the Report and the results of the assessment.

- Section 6.1 describes the recommended process for non-FERC approved and remanded/retired NERC Glossary terms;
- Section 6.2 provides a description of each assessed Revised Term;

[27] Includes one time and annual ongoing incremental costs related to the Reliability Coordinator function.

- Section 6.3 describes the results of the initial screening of the Revised Terms and definitions for adverse reliability impacts and suitability; and
- Section 6.4 summarizes the results of the assessment of the Revised Terms along with BC Hydro's conclusions.

The PC Standards assessed by BC Hydro in the PC Report are based on the defined terms contained in the NERC Glossary dated October 8, 2020. BC Hydro is attaching the October 8, 2020 version of the NERC Glossary to the Report as Appendix B. The NERC Glossary is integral to the reliability standards, and should be adopted by the BCUC in conjunction with the PC Standards to achieve and maintain consistency with NERC reliability standards going forward, provided that:

- Any NERC Glossary terms and definitions that are not approved by FERC on or before November 30, 2020 are of no force or effect in B.C.;
- Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms that have not yet been retired in B.C.; and
- Any FERC approved NERC Glossary terms that have not been assessed by BC Hydro because these NERC Glossary terms are ERCOT, NPCC or Reliability First Regional Definitions or only intended for or associated with reliability standards that have not yet been assessed or adopted in B.C. are of no force or effect in B.C.

6.1 Non-FERC Approved and Remanded/Retired NERC Glossary Terms

BC Hydro notes that new or revised NERC Glossary terms must not be approved for adoption in B.C. until they are assessed by BC Hydro and included in an assessment report. NERC Glossary terms that are not identified as being FERC approved in the NERC Glossary as part of the assessment process could become FERC approved at any time thereafter. These new or revised terms could have impacts on the reliability standards adopted in B.C. BC Hydro recommends that NERC Glossary terms and definitions used in reliability standards that are not identified in the October 8, 2020 version of the NERC Glossary as having a FERC approval date on or before November 30, 2020 should be of no force or effect in B.C.

BC Hydro recommends that any definitions that are identified as being remanded or retired in the NERC Glossary should be ordered by the BCUC to be of no force or effect in B.C. once terms that replace them (if applicable) become effective in B.C. or at such other time as determined appropriate.

6.2 NERC Glossary Terms Assessed by BC Hydro

There have been four terms assessed in this report. These terms are related to standards that have been held in abeyance until the PC function was to be resolved. Initial Screening of the NERC Glossary Terms and Definitions for Adverse Reliability Impacts and Suitability

BC Hydro applies a similar analytical approach to the assessment of the reliability impact, suitability and cost of adoption of the Revised Terms as is described in section 5.1 for the assessment of the PC Standards and the retired reliability standard. The results of BC Hydro's initial screening of the Revised Terms for potential issues regarding adverse reliability impacts and suitability are summarized below in Table 4, which includes:

- The “NERC Glossary Term” column identifies the Revised Terms or Retired Terms;
- The “Changed from BCUC Approved Term and Definition” column, which identifies whether the Revised Term and/or its definition is a revision to a BCUC adopted NERC Glossary term and/or its definition, or whether it is being retired;
- The “Adverse Impact” column, which identifies potential issues relating to adverse reliability impact; and
- The “Suitability Issues” columns, which identify potential suitability issues related to Revised Terms superseding BCUC approved NERC Glossary terms:
  - “Requires NERC Approval/Participation”: Identifies a potential Administrative or Technical Suitability issue as related to continued reliance on approvals by NERC and/or participation in NERC to implement the definition of a Revised Term;
  - “Requires Provisions of Information to NERC or WECC”: Identifies a potential Administrative or Technical Suitability issue with a Revised Term and its definition that requires ongoing reporting of information to NERC or WECC (i.e., lack of clarity on reporting instructions, references to undefined processes or reporting tools, etc.);
  - “Refers to Standard, Term, or Definition not yet FERC Approved”: Identifies a potential Technical or Administrative Suitability issue with a Revised Term and/or its definition as it contains one or more references to reliability standards or other NERC Glossary terms and associated definitions that have not yet been approved by FERC in the U.S., and thereby not assessed for adoption in B.C. This would affect the ability to implement the Revised Term and its definition; and
  - “Other Suitability Issues”: Identifies whether there are any other Administrative or Technical Suitability issues identified, apart from the

categories already defined, that would affect the ability to implement the Revised Term and its definition.

6.3 Initial Screening of NERC Glossary Terms for Adverse Reliability Impact and Suitability

Table 4 Initial Screening of NERC Glossary Terms for Adverse Reliability Impact and Suitability

No.	NERC Glossary Term	Changed from BCUC Approved Term and Definition	Adverse Impact	Suitability Issues				
				Requires NERC Approval/ Participation	Requires Provisions of Information to NERC or WECC		Refers to Standard not yet FERC Approved	Other Suitability/ Applicability Issues
					To NERC	To WECC		
1	Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	No	No	No	No	No	No	No
2	Remedial Action Scheme	Yes	No	No	No	No	No	No
3	Special Protection System (Remedial Action Scheme)	Yes	No	No	No	No	No	No
4	Undervoltage Load Shedding Program	No	No	No	No	No	No	No

6.4 Summary of Final Assessment of the NERC Glossary Terms Assessed in the Report

BC Hydro's final assessment of the four Revised Terms based on survey responses from registered entities is summarized below in Table 5, which includes:

- BC Hydro's final assessment as to whether the adoption of the Revised Terms will give rise to adverse reliability consequences;[28]
- BC Hydro's final assessment as to the suitability of the Revised Terms, based on the criteria described in section 5.1;
- The estimated incremental one-time and ongoing annual costs to achieve and maintain compliance with the reliability standards that refer to the Revised Terms as reported by BC Hydro and survey respondents; and
- BC Hydro's recommended effective dates, based on comments made by registered entities who responded to the stakeholder survey. BC Hydro recommends that these Effective Dates be adopted by the BCUC.

Table 5 Final Assessment Summary of NERC Glossary Terms

NERC Glossary Term	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/year)	Recommended Effective Date
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	None reported	None reported.	None reported.	**BC Hydro Consolidated Recommendation:** Coincide with the effective date of the TPL-007-4 standard pending BCUC adoption. **Feedback Exceptions:** **FortisBC -** Recommended effective date immediately after BCUC approval.

28 No adverse reliability consequences were identified during the final assessment of the Revised Terms and Retired Terms.

NERC Glossary Term	Suitability Issues	One-time Cost ($)	Ongoing Cost ($/year)	Recommended Effective Date
Remedial Action Scheme (**RAS**)	None reported	None reported.	None reported.	**BC Hydro Consolidated Recommendation:** Coincide with the effective date of the PRC-010-2 standard pending BCUC adoption. **Feedback Exceptions:** **FortisBC -** Recommended effective date immediately after BCUC approval.
Special Protection System (Remedial Action Scheme)	None reported	None reported.	None reported.	**BC Hydro Consolidated Recommendation:** Coincide with the effective date of the PRC-010-2 standard pending BCUC adoption. **Feedback Exceptions:** **FortisBC -** Recommended effective date immediately after BCUC approval.
Undervoltage Load Shedding Program	None reported	None reported.	None reported.	**BC Hydro Consolidated Recommendation:** Coincide with the effective date of the PRC-010-2 standard pending BCUC adoption. **Feedback Exceptions:** **FortisBC -** Recommended effective date immediately after BCUC approval.

BC Hydro's assessment is that all four assessed Revised Terms will either maintain or enhance the reliability of the BES in B.C. Based on the assessment above, there are no extra costs required to adopt these four Revised Terms; all costs will be shared with the costs of implementing the associated standards as indicated in section 5.4.

7 Conclusions

BC Hydro has assessed twelve PC Standards with PC dependencies and one retired standard in the Report.

BC Hydro has concluded that, with the exception of the EOP-003-2 PC Standard, the remaining eleven PC Standards assessed in the Report will preserve or enhance the reliability of the BES in B.C., and thus will serve the public interest and are suitable for adoption and retirement, respectively, in B.C. BC Hydro recommends that these eleven PC Standards be adopted and the one retired standard be retired by the BCUC with effective dates that are based on the recommended effective dates included in Table 3, section 5.4 and Attachment A to Appendix D.

As discussed in sections 3.3 and 3.4, in connection with the recommendation to adopt the TPL-001-5.1 and TPL-007-4 PC Standards, BC Hydro recommends that B.C.-specific versions of the TPL-001-5.1 and the TPL-007-4 Implementation Plans be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards. BC Hydro has provided clean B.C.-specific versions of the TPL-001-5.1 and the TPL-007-4 Implementation Plans, along with redlined versions to show changes from the documents developed by NERC, in Attachment D to Appendix D for the BCUC's consideration.

BC Hydro has assessed four Revised Terms held in abeyance due to PC dependencies. BC Hydro has concluded that all four Revised Terms assessed in this Report will preserve or enhance the reliability of the BES in B.C., and thus will serve the public interest and are suitable for adoption in B.C. BC Hydro recommends that these four Revised Terms be adopted by the BCUC with effective dates that are based on the recommended effective dates included in Table 5, section 6.4 and Attachment A to Appendix D.

BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

Appendix A-1

List of Assessed Reliability Standards and NERC Glossary Terms

Table 1 Reliability Standards Assessed[1]

	Standard	Standard Name	FERC Order Approving Standard and Date of Order	Effective Date of FERC Order	U.S. Enforcement Date of Standard	Type	BCUC Approved Standard(s) Being Superseded
1	EOP-003-2[2]	Load Shedding Plans	Docket No. RM11-20-000 Issued May 7, 2012	May 7, 2012	October 1, 2013	Revised (held in abeyance)	EOP-003-1/ TOP-001-1a R8/TOP-007-0 R3/ TOP-008-1 R1
2	FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	Recommend for Retirement RM19-16-000 & RM19-17-000; Order No. 873 Issued September 17, 2020	December 14, 2020	Inactive: December 14, 2020	Retired (held in abeyance)	FAC-013-1
3	MOD-032-1	Data for Power System Modeling and Analysis	Docket No. RD14-5-000 Issued May 1, 2014	May 1, 2014	July 1, 2015	New (held in abeyance)	MOD-010-0/MOD-012-0
4	MOD-033-2	Steady-State and Dynamic System Model Validation	Docket No. RD20-4-000 Issued October 30, 2020	October 30, 2020	April 1, 2021	New	n/a – MOD-033-1 standard in abeyance
5	PRC-006-4	Automatic Underfrequency Load Shedding	Docket No. RD20-4-000 Issued October 30, 2020	October 30, 2020	April1, 2021	Revised	PRC-007-0/PRC-009-0
6	PRC-010-2	Undervoltage Load Shedding	Docket No. RD15-5-000 Issued November 19, 2015	November 19, 2015	April 2, 2017	Revised (held in abeyance)	PRC-010-0/ PRC-021-1/ PRC-022-1

1 The standards highlighted in grey are standards which FERC adopted within the 2020 Assessment Period. These standards are being assessed under this PC Assessment Report as they have requirements dependent on solely the PA/PC function. All other standards listed for assessment in this table also have requirements dependent on solely the PA/PC function and are either (1) adopted in B.C. with only applicable PA/PC related requirements held in abeyance in B.C. or; (2) standards wholly held in abeyance in B.C.

2 The EOP-003-2 standard is superseded by the currently effective EOP-011-1 reliability standard in B.C. in conjunction with PRC-010-2 Requirement 1, pending PRC-010-2 adoption in B.C.; the PRC-010-2 standard is concurrently being assessed under this PC Assessment Report.

	Standard	Standard Name	FERC Order Approving Standard and Date of Order	Effective Date of FERC Order	U.S. Enforcement Date of Standard	Type	BCUC Approved Standard(s) Being Superseded
7	PRC-012-2 Requirements R1: Attachment 1, Section II Parts 6(d) and 6(e) R2: Attachment 2, Section I Parts 7(d) and 7(e), and R4	Remedial Action Schemes	Docket No. RM16-20-000 Issued September 20, 2017	November 27, 2017	January 1, 2021	Reliability standard is currently adopted with specified requirements held in abeyance	n/a – PRC-012-2 standard Requirements R1: Attachment 1, Section II Parts 6(d) and 6(e) R2: Attachment 2, Section I Parts 7(d) and 7(e), and R4 in abeyance
8	PRC-023-2 Requirements R1 – R6 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6	Transmission Relay Loadability	Docket No. RM11-16-000; Order No. 759 Issued March 15, 2012	May 7, 2012	R1, R2, R3 – July 1, 2012 (earliest effective date – see standard for details of phased effective dates) R4, R5 – January 1, 2013 R6 – January 1, 2014	Reliability standard is currently adopted with specified requirements held in abeyance	n/a – PRC-023-2 standard Requirements R1 – R6 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6 in abeyance

	Standard	Standard Name	FERC Order Approving Standard and Date of Order	Effective Date of FERC Order	U.S. Enforcement Date of Standard	Type	BCUC Approved Standard(s) Being Superseded
9	PRC-023-4 Requirements R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6	Transmission Relay Loadability	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued November 19, 2015	January 25, 2016	April1, 2017	Reliability standard is currently adopted with specified requirements held in abeyance	n/a – PRC-023-4 standard Requirements R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6 in abeyance
10	PRC-026-1	Relay Performance During Stable Power Swings	Docket No. RM15-8-000 Issued March 17, 2016	May 23, 2016	January 1, 2018	New (held in abeyance)	n/a – standard in abeyance
11	TPL-001-4 Requirement R7	Transmission System Planning Performance Requirements	Docket No. RM12-1-000 and RM13-9-000; Order No. 786 October 17, 2013	December 23, 2013	January 1, 2016 R1 and R7: January 1, 2015	Reliability standard is currently adopted with specified requirements held in abeyance	n/a – TPL-001-4 standard Requirement 7 in abeyance
12	TPL-001-5.1	Transmission System Planning Performance Requirements	Docket No. RD20-8-000 Issued June 10, 2020	June 10, 2020	July 1, 2023	Revised	TPL-001-4

	Standard	Standard Name	FERC Order Approving Standard and Date of Order	Effective Date of FERC Order	U.S. Enforcement Date of Standard	Type	BCUC Approved Standard(s) Being Superseded
13	TPL-007-4	Transmission System Planned Performance for Geomagnetic Disturbance	Docket No. RD20-3-000; Issued March 19, 2020	March 19, 2020	R6, R10: January 1, 2022 R3, R4, R8: January 1, 2023 R7, R11: January 1, 2024 R12, R13: July 1, 2021 D.A 11.3, D.A 11.4, D.A 11.5, D.A 7.3, D.A 7.4, D.A 7.5, R1, R2, R5, R9: October 1, 2020	New	n/a - TPL-007-3 standard in abeyance

Table 2 NERC Glossary Terms Assessed

	NERC Glossary Term	Acronym	BCUC Approved Term to be Replaced or Retired	FERC Approval Date	U.S. Effective/ Retirement Date
1	Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	GMD	New (held in abeyance)	September 22, 2016	July 1, 2017
2	Remedial Action Scheme	RAS	Remedial Action Scheme	November 19, 2015	April 1, 2017
3	Special Protection System (Remedial Action Scheme)	SPS	Special Protection System (Remedial Action Scheme)	June 23, 2016	April 1, 2017
4	Undervoltage Load Shedding Program	UVLS Program	New (held in abeyance)	November 19, 2015	April 1, 2017

BC Hydro Mandatory Reliability Standards

Planning Coordinator Assessment Report

Appendix A-2

Reliability Standards Assessed by BC Hydro

Clean

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-2

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. ~~**Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).~~

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. *[Violation Risk Factor: High]*

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required. *[Violation Risk Factor: High]*

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]*

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels. *[Violation Risk Factor: High]*

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. *[Violation Risk Factor: High]*

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load. *[Violation Risk Factor: High]*

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions. *[Violation Risk Factor: High]*

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or

Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency. *[Violation Risk Factor: High]*

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Monitoring Responsibility~~
~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

~~1.2. Compliance Monitoring~~
~~One or more of the following methods will be used to assess compliance:~~

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

~~1.3. Additional Reporting Requirement~~

~~No additional reporting required.~~

~~1.4. Data Retention~~

~~Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.~~

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

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

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

~~1.5. Additional Compliance Information~~
~~None~~

2. ~~Violation Severity Levels~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to shed customer load.~~
~~R2~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.~~
~~R3.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.~~
~~R4.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.~~
~~R5.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R6.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.~~
~~R7.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.~~
~~R8.~~	~~N/A~~	~~The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.~~	~~The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.~~	~~The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.~~

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 4, 2010	Adopted by Board of Trustees; Modified R4, R5, R6 and associated VSLs for R2, R4, and R7 to clarify that the requirements don’t apply to automatic underfrequency load shedding.	Revised to eliminate redundancies with PRC-006-1
2	May 7, 2012	FERC Order issued approving EOP-003-2 (approval becomes effective July 10, 2012)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard EOP-003-2 — Load Shedding Plans

United States

Standard	Requirement	Enforcement Date	Inactive Date
EOP-003-2	All	10/01/2013	

Printed On: November 13, 2015, 04:58 PM

A. Introduction

1. **Title:** **Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon**

2. **Number:** FAC-013-2

3. **Purpose:** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.

4. **Applicability:**

   4.1. Planning Coordinators

5. ~~**Effective Date:**~~

   ~~In those jurisdictions where regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after applicable regulatory approval or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-2 are effective.~~

   ~~In those jurisdictions where no regulatory approval is required, the latter of either the first day of the first calendar quarter twelve months after Board of Trustees adoption or the first day of the first calendar quarter six months after MOD-001-1, MOD-028-1, MOD-029-1 and MOD-030-2 are effective.~~

B. Requirements

R1. Each Planning Coordinator shall have a documented methodology it uses to perform an annual assessment of Transfer Capability in the Near-Term Transmission Planning Horizon (Transfer Capability methodology). The Transfer Capability methodology shall include, at a minimum, the following information: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Criteria for the selection of the transfers to be assessed.

1.2. A statement that the assessment shall respect known System Operating Limits (SOLs).

1.3. A statement that the assumptions and criteria used to perform the assessment are consistent with the Planning Coordinator's planning practices.

1.4. A description of how each of the following assumptions and criteria used in performing the assessment are addressed:

1.4.1. Generation dispatch, including but not limited to long term planned outages, additions and retirements.

1.4.2. Transmission system topology, including but not limited to long term planned Transmission outages, additions, and retirements.

1.4.3. System demand.

1.4.4. Current approved and projected Transmission uses.

1.4.5. Parallel path (loop flow) adjustments.

1.4.6. Contingencies

1.4.7. Monitored Facilities.

1.5. A description of how simulations of transfers are performed through the adjustment of generation, Load or both.

R2. Each Planning Coordinator shall issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, to the following entities subject to the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

2.1. Distribute to the following prior to the effectiveness of such revisions:

2.1.1. Each Planning Coordinator adjacent to the Planning Coordinator's Planning Coordinator area or overlapping the Planning Coordinator's area.

2.1.2. Each Transmission Planner within the Planning Coordinator's Planning Coordinator area.

2.2. Distribute to each functional entity that has a reliability-related need for the Transfer Capability methodology and submits a request for that methodology within 30 calendar days of receiving that written request.

R3. If a recipient of the Transfer Capability methodology provides documented concerns with the methodology, the Planning Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Transfer Capability methodology and, if no change will be made to that Transfer Capability methodology, the reason why. *[Violation Risk Factor: Lower][Time Horizon: Long-term Planning]* (Retirement approved by FERC effective January 21, 2014.)

R4. During each calendar year, each Planning Coordinator shall conduct simulations and document an assessment based on those simulations in accordance with its Transfer Capability methodology for at least one year in the Near-Term Transmission Planning Horizon. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R5. Each Planning Coordinator shall make the documented Transfer Capability assessment results available within 45 calendar days of the completion of the assessment to the recipients of its Transfer Capability methodology pursuant to Requirement R2, Parts 2.1 and Part 2.2. However, if a functional entity that has a reliability related need for the results of the annual assessment of the Transfer Capabilities makes a written request for such an assessment after the completion of the assessment, the Planning Coordinator shall make the documented Transfer Capability assessment results available to that entity within 45 calendar days of receipt of the request *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R6. If a recipient of a documented Transfer Capability assessment requests data to support the assessment results, the Planning Coordinator shall provide such data to that entity within 45 calendar days of receipt of the request. The provision of such data shall be subject to the legal and regulatory obligations of the Planning Coordinator's area regarding the disclosure of confidential and/or sensitive information. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

C. Measures

M1. Each Planning Coordinator shall have a Transfer Capability methodology that includes the information specified in Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated e-mail or dated transmittal letters that it provided the new or revised Transfer Capability methodology in accordance with Requirement R2

Each Planning Coordinator shall have evidence, such as dated e-mail or dated transmittal letters, that the Planning Coordinator provided a written response to that commenter in accordance with Requirement R3. (Retirement approved by FERC effective January 21, 2014.)

M3. Each Planning Coordinator shall have evidence such as dated assessment results, that it conducted and documented a Transfer Capability assessment in accordance with Requirement R4.

M4. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment available to the entities in accordance with Requirement R5.

M5. Each Planning Coordinator shall have evidence, such as dated copies of e-mails or transmittal letters, that it made its documented Transfer Capability assessment data available in accordance with Requirement R6.

D. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Enforcement Authority~~

~~Regional Entity~~

~~1.2. Data Retention~~

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

- ~~The Planning Coordinator shall have its current Transfer Capability methodology and any prior versions of the Transfer Capability methodology that were in force since the last compliance audit to show compliance with Requirement R1.~~
- ~~The Planning Coordinator shall retain evidence since its last compliance audit to show compliance with Requirement R2.~~
- ~~The Planning Coordinator shall retain evidence to show compliance with Requirements R3, R4, R5 and R6 for the most recent assessment. (R3 retired-Retirement approved by FERC effective January 21, 2014.)~~

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

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

~~1.3. Compliance Monitoring and Assessment Processes~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.4. Additional Compliance Information~~

~~None~~

2. ~~Violation Severity Levels~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~The Planning Coordinator has a Transfer Capability methodology but failed to address one or two of the items listed in Requirement R1, Part 1.4.~~	~~The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate one of the following Parts of Requirement R1 into that methodology:~~ • ~~Part 1.1~~ • ~~Part 1.2~~ • ~~Part 1.3~~ • ~~Part 1.5~~ ~~OR~~ ~~The Planning Coordinator has a Transfer Capability methodology but failed to address three of the items listed in Requirement R1, Part 1.4.~~	~~The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate two of the following Parts of Requirement R1 into that methodology:~~ • ~~Part 1.1~~ • ~~Part 1.2~~ • ~~Part 1.3~~ • ~~Part 1.5~~ ~~OR~~ ~~The Planning Coordinator has a Transfer Capability methodology but failed to address four of the items listed in Requirement R1, Part 1.4.~~	~~The Planning Coordinator did not have a Transfer Capability methodology.~~ ~~OR~~ ~~The Planning Coordinator has a Transfer Capability methodology, but failed to incorporate three or more of the following Parts of Requirement R1 into that methodology:~~ • ~~Part 1.1~~ • ~~Part 1.2~~ • ~~Part 1.3~~ • ~~Part 1.5~~ ~~OR~~ ~~The Planning Coordinator has a Transfer Capability methodology but failed to address more than four of the items listed in Requirement R1, Part 1.4.~~

~~R2~~	~~The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology after its implementation, but not more than 30 calendar days after its implementation.~~ ~~OR~~ ~~The Planning Coordinator provided the transfer Capability methodology more than 30 calendar days but not more than 60 calendar days after the receipt of a request.~~	~~The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 30 calendar days after its implementation, but not more than 60 calendar days after its implementation.~~ ~~OR~~ ~~The Planning Coordinator provided the Transfer Capability methodology more than 60 calendar days but not more than 90 calendar days after receipt of a request~~	~~The Planning Coordinator notified one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 60 calendar days, but not more than 90 calendar days after its implementation.~~ ~~OR~~ ~~The Planning Coordinator provided the Transfer Capability methodology more than 90 calendar days but not more than 120 calendar days after receipt of a request.~~	~~The Planning Coordinator failed to notify one or more of the parties specified in Requirement R2 of a new or revised Transfer Capability methodology more than 90 calendar days after its implementation.~~ ~~OR~~ ~~The Planning Coordinator provided the Transfer Capability methodology more than 120 calendar days after receipt of a request.~~
~~R3~~ ~~(Retirement approved by FERC effective January 21, 2013.)~~	~~The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 45 calendar days, but not more than 60 calendar days after receipt of the concern.~~	~~The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 60 calendar days, but not more than 75 calendar days after receipt of the concern.~~	~~The Planning Coordinator provided a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 more than 75 calendar days, but not more than 90 calendar days after receipt of the concern.~~	~~The Planning Coordinator failed to provide a documented response to a documented concern with its Transfer Capability methodology as required in Requirement R3 by more than 90 calendar days after receipt of the concern.~~ ~~OR~~ ~~The Planning Coordinator failed to respond to a documented concern with its Transfer Capability methodology.~~

~~R4~~	~~The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, but not by more than 30 calendar days.~~	~~The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 30 calendar days, but not by more than 60 calendar days.~~	~~The Planning Coordinator conducted a Transfer Capability assessment outside the calendar year, by more than 60 calendar days, but not by more than 90 calendar days.~~	~~The Planning Coordinator failed to conduct a Transfer Capability assessment outside the calendar year by more than 90 calendar days.~~ ~~OR~~ ~~The Planning Coordinator failed to conduct a Transfer Capability assessment.~~

~~R5~~	~~The Planning Coordinator made its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 45 calendar days after the requirements of R5,, but not more than 60 calendar days after completion of the assessment.~~	~~The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 60 calendar days after the requirements of R5, but not more than 75 calendar days after completion of the assessment.~~	~~The Planning Coordinator made its Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 75 calendar days after the requirements of R5, but not more than 90 days after completion of the assessment.~~	~~The Planning Coordinator failed to make its documented Transfer Capability assessment available to one or more of the recipients of its Transfer Capability methodology more than 90 days after the requirements of R5.~~ ~~OR~~ ~~The Planning Coordinator failed to make its documented Transfer Capability assessment available to any of the recipients of its Transfer Capability methodology under the requirements of R5.~~
~~R6~~	~~The Planning Coordinator provided the requested data as required in Requirement R6 more than 45 calendar days after receipt of the request for data, but not more than 60 calendar days after the receipt of the request for data.~~	~~The Planning Coordinator provided the requested data as required in Requirement R6 more than 60 calendar days after receipt of the request for data, but not more than 75 calendar days after the receipt of the request for data.~~	~~The Planning Coordinator provided the requested data as required in Requirement R6 more than 75 calendar days after receipt of the request for data, but not more than 90 calendar days after the receipt of the request for data.~~	~~The Planning Coordinator provided the requested data as required in Requirement R6 more than 90 after the receipt of the request for data.~~ ~~OR~~ ~~The Planning Coordinator failed to provide the requested data as required in Requirement R6.~~

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Lower cased the word “draft” and “drafting team” where appropriate. 3. Changed Anticipated Action #5, page 1, from “30-day” to “Thirty-day.” 4. Added or removed “periods.”	01/20/05
2	01/24/11	Approved by BOT	
2	11/17/11	FERC Order issued approving FAC-013-2	
2	05/17/12	FERC Order issued directing the VRF’s for Requirements R1. and R4. be changed from “Lower” to “Medium.” FERC Order issued correcting the High and Severe VSL language for R1.	
2	02/7/13	R3 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	11/21/13	R3 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

* FOR INFORMATIONAL PURPOSES ONLY *

Effective Date of Standard: FAC-013-2 — Assessment of Transfer Capability for the Near-term Transmission Planning Horizon

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
FAC-013-2	R1.	04/01/2013		12/14/2020
FAC-013-2	R2.	04/01/2013		12/14/2020
FAC-013-2	R3.	04/01/2013		01/21/2014
FAC-013-2	R4.	04/01/2013		12/14/2020
FAC-013-2	R5.	04/01/2013		12/14/2020
FAC-013-2	R6.	04/01/2013		12/14/2020
FAC-013-2	1.1.	04/01/2013		12/14/2020
FAC-013-2	1.2.	04/01/2013		12/14/2020
FAC-013-2	1.3.	04/01/2013		12/14/2020
FAC-013-2	1.4.	04/01/2013		12/14/2020
FAC-013-2	1.5.	04/01/2013		12/14/2020
FAC-013-2	2.1.	04/01/2013		12/14/2020
FAC-013-2	2.2.	04/01/2013		12/14/2020
FAC-013-2	1.4.1.	04/01/2013		12/14/2020
FAC-013-2	1.4.2.	04/01/2013		12/14/2020
FAC-013-2	1.4.3.	04/01/2013		12/14/2020
FAC-013-2	1.4.4.	04/01/2013		12/14/2020
FAC-013-2	1.4.5.	04/01/2013		12/14/2020
FAC-013-2	1.4.6.	04/01/2013		12/14/2020
FAC-013-2	1.4.7.	04/01/2013		12/14/2020
FAC-013-2	2.1.1.	04/01/2013		12/14/2020
FAC-013-2	2.1.2.	04/01/2013		12/14/2020

Printed On: December 13, 2020, 11:52 PM

A. Introduction

1. **Title: Data for Power System Modeling and Analysis**
2. **Number: MOD-032-1**
3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Balancing Authority

4.1.2 Generator Owner

4.1.3 Load Serving Entity

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

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

4.1.5 Resource Planner

4.1.6 Transmission Owner

4.1.7 Transmission Planner

4.1.8 Transmission Service Provider

5. ~~**Effective Date:**~~

~~MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority~~

~~is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

R1. Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. The data listed in Attachment 1.

1.2. Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

1.2.1. Data format;

1.2.2. Level of detail to which equipment shall be modeled;

1.2.3. Case types or scenarios to be modeled; and

1.2.4. A schedule for submission of data at least once every 13 calendar months.

1.3. Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

M1. Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. Provide either updated data or an explanation with a technical basis for maintaining the current data;

3.2. Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

M3. Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

R4. Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Enforcement Authority~~

~~"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~1.2. Evidence Retention~~

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

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

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

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

~~1.3. Compliance Monitoring and Assessment Processes:~~

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~1.4. Additional Compliance Information~~

~~None~~

Table of Compliance Elements

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~**Long-term Planning**~~	~~**Lower**~~	~~The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.~~	~~The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.~~	~~The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.~~	~~The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1;~~ ~~OR~~ ~~The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified~~

						in Requirement R1.
~~R2~~	~~Long-term Planning~~	~~Medium~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s);~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission~~

			~~steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified~~	~~Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning~~	~~Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning~~	~~Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;~~ ~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;~~

			~~by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.~~	~~Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.~~	~~Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.~~	~~OR~~ ~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.~~
~~R3~~	**~~Long-term Planning~~**	**~~Lower~~**	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service~~	~~The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service~~

			~~Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).~~	~~Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).~~	~~Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).~~	~~Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).~~

~~R4~~	~~**Long-term Planning**~~	~~**Medium**~~	~~The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.~~	~~The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.~~	~~The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.~~	~~The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO]	6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]	purposes. [BA, GO, LSE, TO, TSP]

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* 9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

Rationale:

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

Rationale for R1:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

1) reduce the quantity of MOD standards;
2) add short circuit data as a requirement to the MOD standards; and
3) supply data and models:

a. add requirement identifying who provides and who receives data;
b. identify acceptability;
c. standard format;
d. how to deal with new technologies (user written models if no standard model exists); and
e. shareability.

4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*" (Emphasis added).

This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving	See Implementation Plan

		MOD-032-1.	posted on the Reliability Standards web page for details on enforcement dates for Requirements.

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**
2. **Number: MOD-033-2**
3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.
4. **Applicability:**
   4.1. Functional Entities:
   - **4.1.1** Planning Coordinator
   - **4.1.2** Reliability Coordinator
   - **4.1.3** Transmission Operator
5. ~~**Effective Date:** See Implementation Plan.~~

B. Requirements and Measures

R1. Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation;

1.2. Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;

1.3. Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

M1. Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.

R2. Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M2. Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Enforcement Authority~~

~~"Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~1.2. Evidence Retention~~

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

~~The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

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

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

~~1.3. Compliance Monitoring and Assessment Processes:~~

~~Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~1.4. Additional Compliance Information~~

~~None~~

Table of Compliance Elements

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~Long-term Planning~~	~~Medium~~	~~The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as~~	~~The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months;~~ ~~OR~~	~~The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months;~~ ~~OR~~	~~The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1;~~ ~~OR~~ ~~The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months;~~ ~~OR~~ ~~The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
			~~required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.~~	~~The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.~~	~~The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.~~	~~months (or the next dynamic local event in cases where there is more than 24 months between events).~~
~~R2~~	~~**Long-term Planning**~~	~~**Lower**~~	~~The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning~~	~~The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning~~	~~The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning~~	~~The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
			~~Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.~~	~~Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.~~	~~Coordinator within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.~~	~~Coordinator within 75 calendar days;~~ ~~OR~~ ~~The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of "at least once every 24 calendar months" is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a "month 23" dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event's occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event's occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator's system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator's system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

Rationale:

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

Rationale for R1:

In FERC Order No. 693, paragraph 1210, the Commission directed inclusion of "a requirement that the models be validated against actual system responses." Furthermore, the Commission directs in paragraph 1211, "that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and

B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Rationale for R2:
The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.
1	May 1, 2014	FERC Order issued approving MOD-033-1.	
2	February 6, 2020	Adopted by the NERC Board of Trustees.	Revisions under Project 2017-07

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-4

3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. **Applicability:**

   4.1. Planning Coordinators

   4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:

   4.2.1 Transmission Owners

   4.2.2 Distribution Providers

   4.2.3 UFLS-Only Distribution Providers

   4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.

5. ~~**Effective Date:**~~

   ~~See Implementation Plan~~

B. Requirements and Measures

R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.

R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

2.1. Those islands selected by applying the criteria in Requirement R1, and

2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and

2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.

M2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.

R3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-4 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-4 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
- Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
- Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

R4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1.

4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1.

4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1.

4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 — Attachment 1.

4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 — Attachment 1.

4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 — Attachment 1.

4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.

R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*

- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
- Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

M5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.

R6. Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*

M6. Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.

R7. Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.

R8. Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*

M8. Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.

R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*

M9. Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, per Requirement R9.

R10. Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*

M10. Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, per Requirement R10.

R11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

11.1. The performance of the UFLS equipment,

11.2. The effectiveness of the UFLS program.

M11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.

R12. Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

R13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

M13. Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

M14. Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. *[VRF: High][Time Horizon: Long-term Planning]*

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Enforcement Authority~~

~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~1.2. Evidence Retention~~

~~Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 as well as any evidence necessary to show compliance since the last compliance audit.~~
- ~~Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.~~
- ~~Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.~~
- ~~Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.~~
- ~~Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.~~
- ~~Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.~~
- ~~Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.~~

~~If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.~~

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

~~1.3. Compliance Monitoring and Assessment Processes:~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Violation Investigation~~

~~Self-Reporting~~

~~Complaints~~

~~1.4. Additional Compliance Information~~

~~None~~

Violation Severity Levels

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**R1**~~	~~N/A~~	~~The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.~~ ~~OR~~ ~~The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.~~	~~The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.~~	~~The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.~~
~~**R2**~~	~~N/A~~	~~The Planning Coordinator identified an island(s) to~~	~~The Planning Coordinator identified an island(s) to serve~~	~~The Planning Coordinator identified an island(s) to serve~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.~~	~~as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.~~	~~as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.~~ ~~OR~~ ~~The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.~~
~~**R3**~~	~~N/A~~	~~The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.~~	~~The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s)., but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.~~	~~The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).,but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.~~ ~~OR~~ ~~The Planning Coordinator failed to develop a UFLS program~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~including notification of and a schedule for implementation by UFLS entities within its area~~
~~R4~~	~~The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.~~	~~The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.~~	~~The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.~~	~~The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.~~ ~~OR~~ ~~The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**R5**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.~~
~~**R6**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.~~
~~**R7**~~	~~The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.~~	~~The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.~~	~~The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.~~	~~The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request.~~ ~~OR~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.~~
~~R8~~	~~The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.~~	~~The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.~~ ~~OR~~ ~~The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.~~	~~The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.~~	~~The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.~~ ~~OR~~ ~~The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.~~
~~R9~~	~~The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS~~	~~The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design~~	~~The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design~~	~~The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation,~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
	~~program design and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.~~	~~and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.~~	~~and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.~~	~~including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.~~
~~**R10**~~	~~The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.~~	~~The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.~~	~~The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.~~	~~The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.~~
~~**R11**~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program,~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
	~~the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.~~	~~the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.~~	~~UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.~~ ~~OR~~ ~~The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as specified in Requirement R11, Parts11.1 or 11.2.~~	~~conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.~~ ~~OR~~ ~~The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.~~ ~~OR~~ ~~The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~as specified in Requirement R11, Parts 11.1 and 11.2.~~
~~**R12**~~	~~N/A~~	~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.~~	~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.~~	~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation.~~ ~~OR~~ ~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.~~
~~**R13**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13~~
~~**R14**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.~~
~~**R15**~~	~~N/A~~	~~The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement~~	~~The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement~~	~~The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement~~

~~R #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.~~	~~R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.~~	~~R3, but failed to develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area.~~ ~~OR~~ ~~The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.~~

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

Rationale for Requirement D.A.3:

There are two modifications for requirement D.A.3 :

1. 25% Generation Deficiency : Since the Quebec Interconnection has no potential viable BES Island in underfrequency conditions, the largest generation deficiency scenarios are limited to extreme contingencies not already covered by RAS.

Based on Hydro-Québec TransÉnergie Transmission Planning requirements, the stability of the network shall be maintained for extreme contingencies using a case representing internal transfers not expected to be exceeded 25% of the time.

The Hydro-Québec TransÉnergie defense plan to cover these extreme contingencies includes two RAS (RPTC- generation rejection and remote load shedding and TDST - a centralized UVLS) and the UFLS.

2. Frequency performance curve (attachment 1A) : Specific cases where a small generation deficiency using a peak case scenario with the minimum requirement of spinning reserve can lead to an acceptable frequency deviation in the Quebec Interconnection while stabilizing between the PRC-006-2 requirement (59.3 Hz) and the UFLS anti-stall threshold (59.0 Hz).

An increase of the anti-stall threshold to 59.3 Hz would correct this situation but would cause frequent load shedding of customers without any gain of system reliability. Therefore, it is preferable to lower the steady state frequency minimum value to 59.0 Hz.

The delay in the performance characteristics curve is harmonized between D.A.3 and R.3 to 60 seconds.

Rationale for Requirements D.A.3.3. and D.A.4:

The **Q**uebec Interconnection has its own definition of BES. In Quebec, the vast majority of BES generating plants/facilities are not directly connected to the BES. For simulations to take into account sufficient generating resources D.A.3.3 and D.A.4 need simply refer to BES generators, plants or facilities since these are listed in a Registry approved by Québec's Regulatory Body (Régie de l'Énergie).

D.A.3. Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from each of these extreme events:

- Loss of the entire capability of a generating station.
- Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.
- Loss of all transmission circuits on a common right-of-way.
- Three-phase fault with failure of a circuit breaker to operate and correct operation of a breaker failure protection system and its associated breakers.
- Three-phase fault on a circuit breaker, with normal fault clearing.
- The operation or partial operation of a RAS for an event or condition for which it was not intended to operate.

[VRF: High][Time Horizon: Long-term Planning]

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-4 - Attachment 1A, either for 60 seconds or until a steady-state condition between 59.0 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-4 - Attachment 1A, either for 60 seconds or until a steady-state condition between 59.0 Hz and 60.7 Hz is reached, and

D.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each Quebec BES generator bus and associated generator step-up transformer high-side bus

M.D.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.A.3 Parts D.A.3.1 through D.A.3.3.

D.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

D.A.4.1 Underfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities that trip above the Generator

Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1A, and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of Quebec BES plants/facilities that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 - Attachment 1A, and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement D.A.4 Parts D.A.4.1 through D.A.4.3.

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	N/A	The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area.
DA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement D.A.3 but the simulation failed to include one (1) of the items as	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement D.A.3 but the simulation failed to include two (2) of the items as	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement D.A.3 but the simulation failed to include all of the items as

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
		specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

D.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

M.D.B.1. Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System.

M.D.B.2. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-4 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-4 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

D.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

D.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

D.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

D.B.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.

M.D.B.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement D.B.3 Parts D.B.3.1 through D.B.3.3.

D.B.4. Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*

D.B.4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1.

D.B.4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1.

D.B.4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the

Generator Underfrequency Trip Modeling curve in PRC-006-4 - Attachment 1.

D.B.4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 — Attachment 1.

D.B.4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 — Attachment 1.

D.B.4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-4 — Attachment 1.

D.B.4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.B.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement D.B.4 Parts D.B.4.1 through D.B.4.7.

D.B.11. Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.B.11. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement D.B.11.

D.B.12. Each Planning Coordinator, in whose islanding event assessment (per D.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other

Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

M.D.B.12. Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**D.B.1**~~	~~N/A~~	~~The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands~~ ~~OR~~ ~~The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands~~	~~The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands~~	~~The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands~~

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**D.B.2**~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2~~	~~The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement D.B.2, Parts D.B.2.1 or D.B.2.2~~ ~~OR~~ ~~The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.~~
~~**D.B.3**~~	~~N/A~~	~~The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions~~	~~The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in simulations of underfrequency conditions~~	~~The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in simulations of underfrequency conditions~~

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~OR~~ ~~The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.~~
~~**D.B.4**~~	~~The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.~~	~~The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.~~	~~The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.~~	~~The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.~~ ~~OR~~

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement D.B.3 for each island identified in Requirement D.B.2~~
~~D.B.11~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 13 months but~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 14 months but~~	~~The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a~~

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
	~~less than or equal to 13 months of actuation.~~	~~less than or equal to 14 months of actuation.~~	~~less than or equal to 15 months of actuation.~~ ~~OR~~ ~~The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement D.B.11, Parts D.B.11.1 or D.B.11.2.~~	~~time greater than 15 months of actuation.~~ ~~OR~~ ~~The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.~~ ~~OR~~ ~~The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included~~

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2.~~
~~**D.B.12**~~	~~N/A~~	~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.~~	~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.~~	~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.~~ ~~OR~~ ~~The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area~~

~~D #~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~to consider the identified deficiencies~~

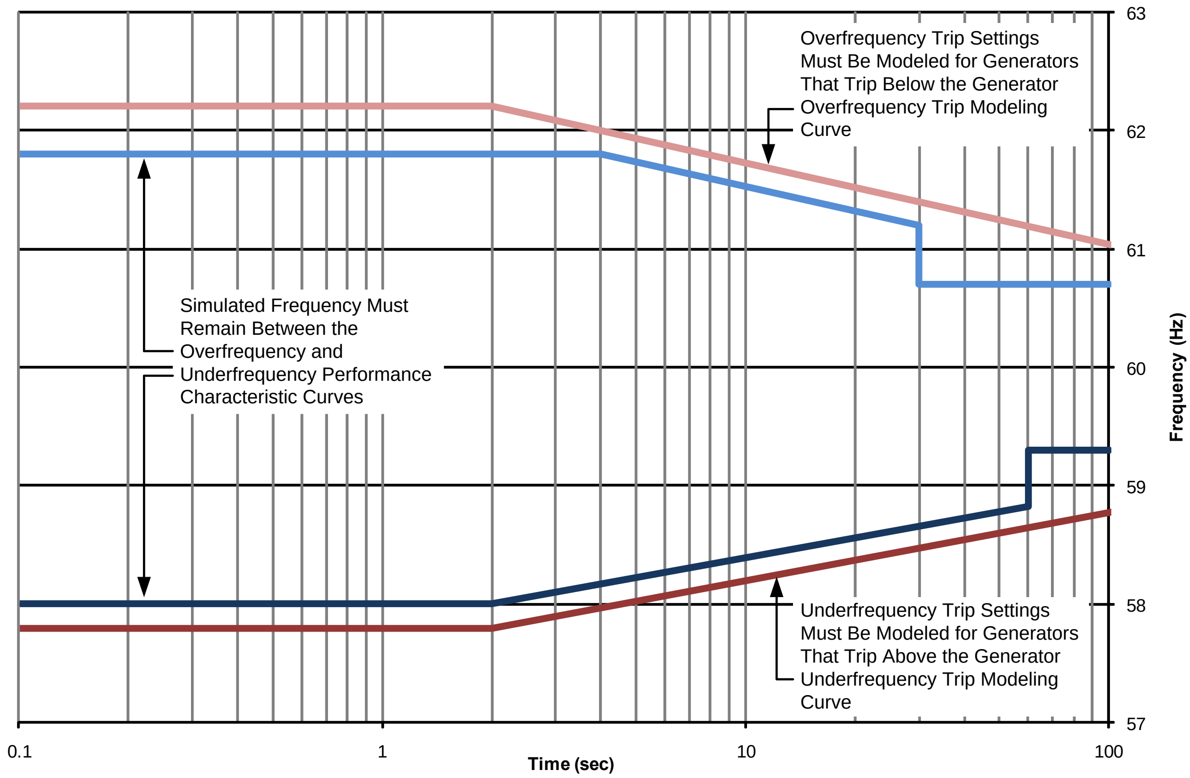
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.
3	August 10, 2017	Adopted by the NERC Board of Trustees	Revisions to the Regional Variance for the Quebec Interconnection.
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07

PRC-006-4 – Attachment 1

Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6



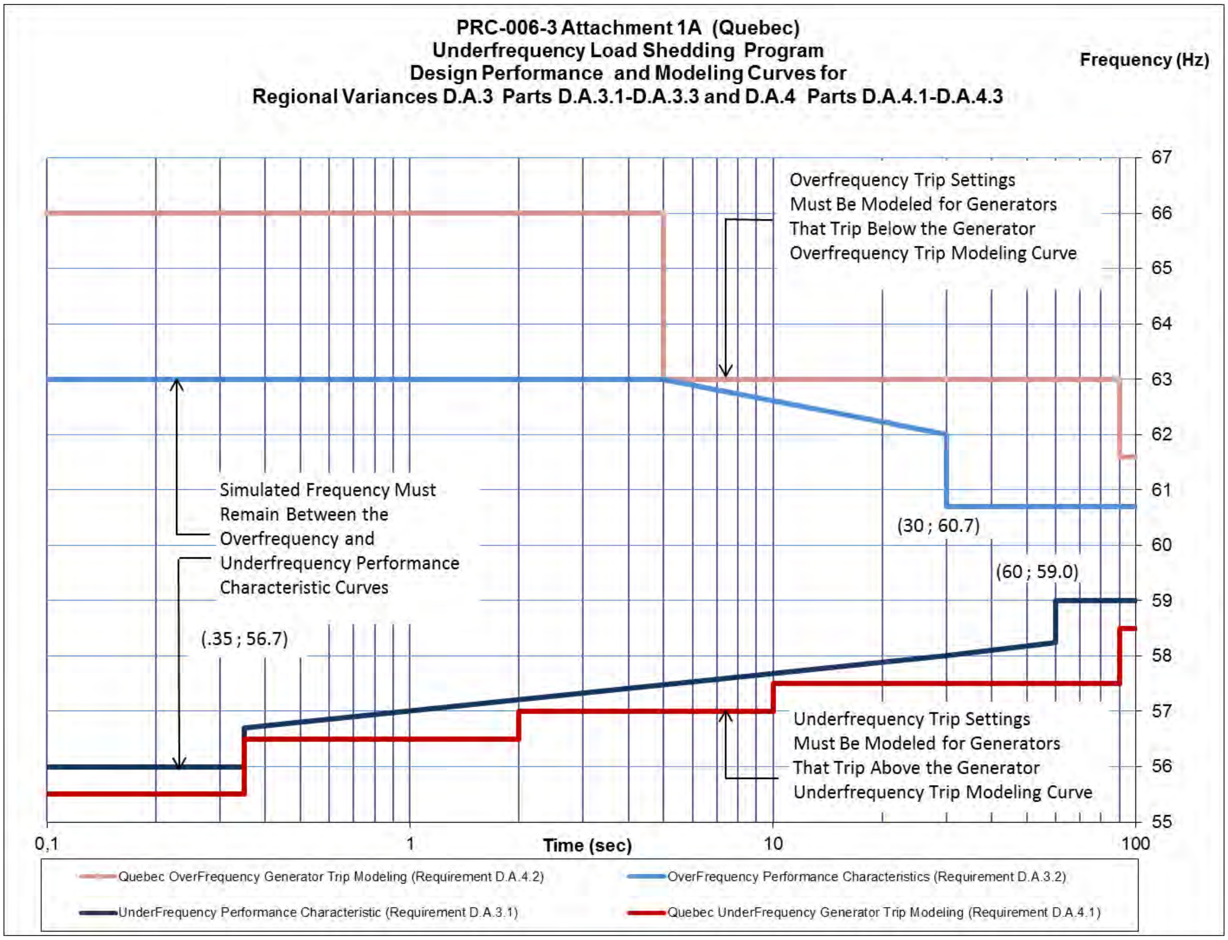
Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
t ≤ 2 s	t > 2 s	t ≤ 4 s	4 s < t ≤ 30 s	t > 30 s
f = 62.2 Hz	f = -0.686log(t) + 62.41 Hz	f = 61.8 Hz	f = -0.686log(t) + 62.21 Hz	f = 60.7 Hz

Generator Underfrequency Trip Modeling	Underfrequency Performance Characteristic

t ≤ 2 s	t > 2 s	t ≤ 2 s	2 s < t ≤ 60 s	t > 60 s
f = 57.8 Hz	f = 0.575log(t) + 57.63 Hz	f = 58.0 Hz	f = 0.575log(t) + 57.83 Hz	f = 59.3 Hz


PRC-006-3 Attachment 1A (Quebec)
Underfrequency Load Shedding Program
Design Performance and Modeling Curves for
Regional Variances D.A.3 Parts D.A.3.1-D.A.3.3 and D.A.4 Parts D.A.4.1-D.A.4.3
Frequency (Hz)
Overfrequency Trip Settings Must Be Modeled for Generators That Trip Below the Generator Overfrequency Trip Modeling Curve
Simulated Frequency Must Remain Between the Overfrequency and Underfrequency Performance Characteristic Curves
(30 ; 60.7)
(60 ; 59.0)
(.35 ; 56.7)
Underfrequency Trip Settings Must Be Modeled for Generators That Trip Above the Generator Underfrequency Trip Modeling Curve
67
66
65
64
63
62
61
60
59
58
57
56
55
0,1
1
10
100
Time (sec)
Quebec OverFrequency Generator Trip Modeling (Requirement D.A.4.2)
OverFrequency Performance Characteristics (Requirement D.A.3.2)
UnderFrequency Performance Characteristic (Requirement D.A.3.1)
Quebec UnderFrequency Generator Trip Modeling (Requirement D.A.4.1)

Rationale:

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

Rationale for R9:
The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R10:
The "Corrective Action Plan" language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word "application" was replaced with "implementation." (See Requirements R3, R14 and R15)

Rationale for R15:
Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A "Corrective Action Plan" is defined in the NERC Glossary of Terms as, "a list of actions and an associated timetable for implementation to remedy a specific problem." Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

A. Introduction

1. **Title:** Undervoltage Load Shedding
2. **Number:** PRC-010-2
3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator.

   4.1.2 Transmission Planner.

   4.1.3 Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator.

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

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Enforcement Authority~~

~~As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~1.2. Evidence Retention~~

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

~~The Planning Coordinator, Transmission Planner, Distribution Provider, and Transmission Owner shall keep data or evidence to show compliance as identified~~

~~below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

~~The applicable entity shall retain documentation as evidence for six calendar years.~~

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

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

~~1.3. Compliance Monitoring and Assessment Processes~~

~~"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~Long-term Planning~~	~~High~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R2~~	~~Long-term Planning~~	~~High~~	~~N/A~~	~~N/A~~	~~The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2.~~ ~~OR~~ ~~The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.~~	~~The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.~~
~~R3~~	~~Long-term Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R4~~	~~Operations Planning~~	~~Medium~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event.~~ ~~OR~~ ~~The applicable entity failed to perform an assessment in accordance with Requirement R4.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R5~~	~~Operations Planning~~	~~Medium~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days.~~ ~~OR~~ ~~The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R6~~	~~Operations Planning~~	~~Lower~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days.~~ ~~OR~~ ~~The applicable entity failed to update the database in accordance with Requirement R6.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R7~~	~~Operations Planning~~	~~Lower~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule.~~ ~~OR~~ ~~The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule.~~ ~~OR~~ ~~The applicable entity failed to provide data in accordance with Requirement R7.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R8~~	~~Operations Planning~~	~~Lower~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days.~~ ~~OR~~ ~~The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	
0	February 7, 2013	Adopted by NERC Board of Trustees	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2	May 7, 2015	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.
2	November 19, 2015	FERC Letter Order issued approving PRC-010-2. Docket RD15-5-000	

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

Guidelines for UVLS Program Definition

The definition for the term, "Undervoltage Load Shedding Program" or "UVLS Program" includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.

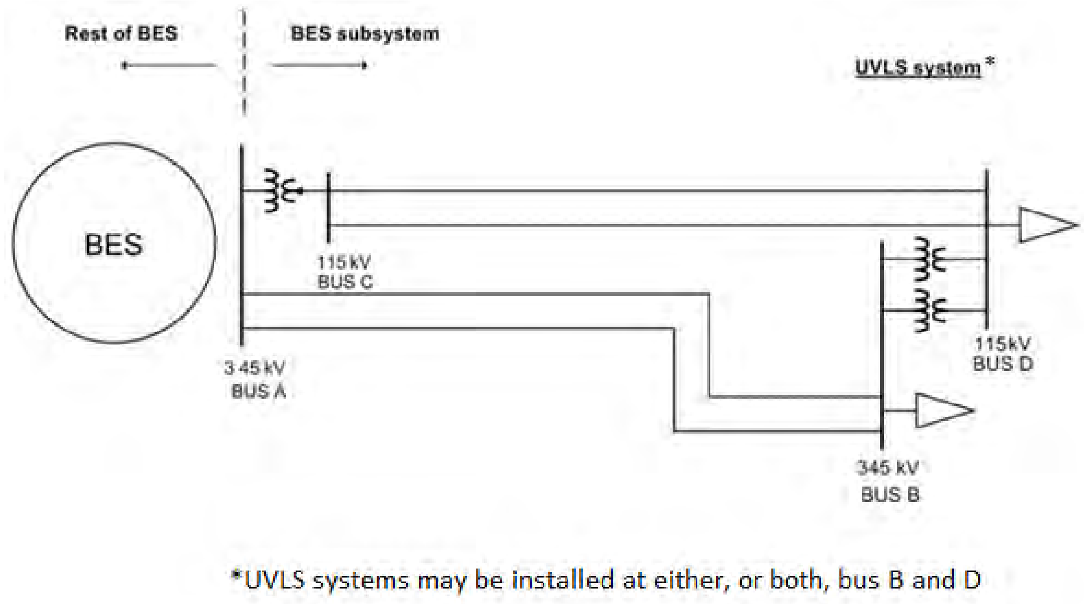


Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection*.[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The "within three

[3] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4,5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

[4] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).
[5] Adopted by the NERC Board of Trustees on November 14, 2014.
[6] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).
[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).
[8] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).
[9] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and

[10] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).
[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.
[12] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).

consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and

[13] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
[14] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).
[15] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
[16] (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

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[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20Coordination.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[19] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*)[21,22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

Rationale

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

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning

[20] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).
[21] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency%20Load%20Shedding).
[22] Adopted by the NERC Board of Trustees on November 14, 2014.

Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-010-2 — Undervoltage Load Shedding

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-010-2	All	04/02/2017	

Printed On: April 15, 2016, 02:38 PM

A. Introduction

1. **Title:** Remedial Action Schemes
2. **Number:** PRC-012-2
3. **Purpose:** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Reliability Coordinator
     - **4.1.2.** Planning Coordinator
     - **4.1.3.** RAS-entity – the Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS
   - **4.2. Facilities:**
     - **4.2.1.** Remedial Action Schemes (RAS)
5. **Effective Date*:** See the Implementation Plan for PRC-012-2.

B. Requirements and Measures

R1. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity shall provide the information identified in Attachment 1 for review to the Reliability Coordinator(s) where the RAS is located. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, a copy of the Attachment 1 documentation and the dated communications with the reviewing Reliability Coordinator(s) in accordance with Requirement R1.

R2. Each Reliability Coordinator that receives Attachment 1 information pursuant to Requirement R1 shall, within four full calendar months of receipt or on a mutually agreed upon schedule, perform a review of the RAS in accordance with Attachment 2, and provide written feedback to each RAS-entity. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated reports, checklists, or other documentation detailing the RAS review, and the dated communications with the RAS-entity in accordance with Requirement R2.

R3. Prior to placing a new or functionally modified RAS in service or retiring an existing RAS, each RAS-entity that receives feedback from the reviewing Reliability Coordinator(s) identifying reliability issue(s) shall resolve each issue to obtain

***Mandatory BC Effective Date: October 1, 2021, and R1 Attachment 1, Section II Parts 6(d), 6(e); R2 Attachment 2, Section I Parts 7(d), 7(e); and R4: TBD**

approval of the RAS from each reviewing Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated documentation and communications with the reviewing Reliability Coordinator that no reliability issues were identified during the review or that all identified reliability issues were resolved in accordance with Requirement R3.

R4. Each Planning Coordinator, at least once every five full calendar years, shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Perform an evaluation of each RAS within its planning area to determine whether:

4.1.1. The RAS mitigates the System condition(s) or Contingency(ies) for which it was designed.

4.1.2. The RAS avoids adverse interactions with other RAS, and protection and control systems.

4.1.3. For limited impact[1] RAS, the inadvertent operation of the RAS or the failure of the RAS to operate does not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

4.1.4. Except for limited impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following:

4.1.4.1. The BES shall remain stable.

4.1.4.2. Cascading shall not occur.

4.1.4.3. Applicable Facility Ratings shall not be exceeded.

4.1.4.4. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

4.1.4.5. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

4.1.5. Except for limited impact RAS, a single component failure in the RAS, when the RAS is intended to operate does not prevent the BES from meeting the same performance requirements (defined in Reliability

[1] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed.

4.2. Provide the results of the RAS evaluation including any identified deficiencies to each reviewing Reliability Coordinator and RAS-entity, and each impacted Transmission Planner and Planning Coordinator.

M4. Acceptable evidence may include, but is not limited to, dated reports or other documentation of the analyses comprising the evaluation(s) of each RAS and dated communications with the RAS-entity(ies), Transmission Planner(s), Planning Coordinator(s), and the reviewing Reliability Coordinator(s) in accordance with Requirement R4.

R5. Each RAS-entity, within 120 full calendar days of a RAS operation or a failure of its RAS to operate when expected, or on a mutually agreed upon schedule with its reviewing Reliability Coordinator(s), shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Participate in analyzing the RAS operational performance to determine whether:

5.1.1. The System events and/or conditions appropriately triggered the RAS.

5.1.2. The RAS responded as designed.

5.1.3. The RAS was effective in mitigating BES performance issues it was designed to address.

5.1.4. The RAS operation resulted in any unintended or adverse BES response.

5.2. Provide the results of RAS operational performance analysis that identified any deficiencies to its reviewing Reliability Coordinator(s).

M5. Acceptable evidence may include, but is not limited to, dated documentation detailing the results of the RAS operational performance analysis and dated communications with participating RAS-entities and the reviewing Reliability Coordinator(s) in accordance with Requirement R5.

R6. Each RAS-entity shall participate in developing a Corrective Action Plan (CAP) and submit the CAP to its reviewing Reliability Coordinator(s) within six full calendar months of: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

- Being notified of a deficiency in its RAS pursuant to Requirement R4, or
- Notifying the Reliability Coordinator of a deficiency pursuant to Requirement R5, Part 5.2, or
- Identifying a deficiency in its RAS pursuant to Requirement R8.

M6. Acceptable evidence may include, but is not limited to, a dated CAP and dated communications among each reviewing Reliability Coordinator and each RAS-entity in accordance with Requirement R6.

R7. Each RAS-entity shall, for each of its CAPs developed pursuant to Requirement R6: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

7.1. Implement the CAP.

7.2. Update the CAP if actions or timetables change.

7.3. Notify each reviewing Reliability Coordinator if CAP actions or timetables change and when the CAP is completed.

M7. Acceptable evidence may include, but is not limited to, dated documentation such as CAPs, project or work management program records, settings sheets, work orders, maintenance records, and communication with the reviewing Reliability Coordinator(s) that documents the implementation, updating, or completion of a CAP in accordance with Requirement R7.

R8. Each RAS-entity shall participate in performing a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-Protection System components: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

- At least once every six full calendar years for all RAS not designated as limited impact, or
- At least once every twelve full calendar years for all RAS designated as limited impact

M8. Acceptable evidence may include, but is not limited to, dated documentation detailing the RAS operational performance analysis for a correct RAS segment or an end-to-end operation (Measure M5 documentation), or dated documentation demonstrating that a functional test of each RAS segment or an end-to-end test was performed in accordance with Requirement R8.

R9. Each Reliability Coordinator shall update a RAS database containing, at a minimum, the information in Attachment 3 at least once every twelve full calendar months. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Acceptable evidence may include, but is not limited to, dated spreadsheets, database reports, or other documentation demonstrating a RAS database was updated in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
The British Columbia Utilities Commission

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances

where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The RAS-entity (Transmission Owner, Generator Owner, and Distribution Provider) shall each keep data or evidence to show compliance with Requirements R1, R3, R5, R6, R7, and R8, and Measures M1, M3, M5, M6, M7, and M8 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Reliability Coordinator shall each keep data or evidence to show compliance with Requirements R2 and R9, and Measures M2 and M9 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Planning Coordinator shall each keep data or evidence to show compliance with Requirement R4 and Measure M4 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a RAS-entity (Transmission Owner, Generator Owner or Distribution Provider), Reliability Coordinator, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The RAS-entity failed to provide the information identified in Attachment 1 to each Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R1.
R2.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by less than or equal to 30 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The reviewing Reliability Coordinator performed the review and provided the written feedback in accordance with Requirement R2, but was late by more than 90 full calendar days. OR The reviewing Reliability Coordinator failed to perform the review or provide feedback in accordance with Requirement R2.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	N/A	N/A	N/A	The RAS-entity failed to resolve identified reliability issue(s) to obtain approval from each reviewing Reliability Coordinator prior to placing a new or functionally modified RAS in service or retiring an existing RAS in accordance with Requirement R3.
R4.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by less than or equal to 30 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate one of the Parts 4.1.1 through 4.1.5.	The Planning Coordinator performed the evaluation in accordance with Requirement R4, but was late by more than 90 full calendar days. OR The Planning Coordinator performed the evaluation in accordance with Requirement R4, but failed to evaluate two or more of the Parts 4.1.1 through 4.1.5. OR The Planning Coordinator

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				performed the evaluation in accordance with Requirement R4, but failed to provide the results to one or more of the receiving entities listed in Part 4.2. OR The Planning Coordinator failed to perform the evaluation in accordance with Requirement R4.
R5.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by less than or equal to 10 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address one of the Parts 5.1.1 through 5.1.4.	The RAS-entity performed the analysis in accordance with Requirement R5, but was late by more than 30 full calendar days. OR The RAS-entity performed the analysis in accordance with Requirement R5, but failed to address two or more of the Parts 5.1.1 through 5.1.4. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The RAS-entity performed the analysis in accordance with Requirement R5, but failed to provide the results (Part 5.2) to one or more of the reviewing Reliability Coordinator(s). OR The RAS-entity failed to perform the analysis in accordance with Requirement R5.
R6.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by less than or equal to 10 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 10 full calendar days but less than or equal to 20 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 20 full calendar days but less than or equal to 30 full calendar days.	The RAS-entity developed a Corrective Action Plan and submitted it to its reviewing Reliability Coordinator(s) in accordance with Requirement R6, but was late by more than 30 full calendar days. OR The RAS-entity developed a Corrective Action Plan but failed to submit it to one or more of its reviewing

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Reliability Coordinator(s) in accordance with Requirement R6. OR The RAS-entity failed to develop a Corrective Action Plan in accordance with Requirement R6.
R7.	The RAS-entity implemented a CAP in accordance with Requirement R7, Part 7.1, but failed to update the CAP (Part 7.2) if actions or timetables changed, or failed to notify (Part 7.3) each of the reviewing Reliability Coordinator(s) of the updated CAP or completion of the CAP.	N/A	N/A	The RAS-entity failed to implement a CAP in accordance with Requirement R7, Part 7.1.
R8.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by less than or equal to 30 full calendar days.	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 30 full calendar days but less than or equal to 60	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 60 full calendar days but less than or equal to 90	The RAS-entity performed the functional test for a RAS as specified in Requirement R8, but was late by more than 90 full calendar days.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		full calendar days.	full calendar days.	OR The RAS-entity failed to perform the functional test for a RAS as specified in Requirement R8.
R9.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by less than or equal to 30 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 30 full calendar days but less than or equal to 60 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9, but was late by more than 60 full calendar days but less than or equal to 90 full calendar days.	The Reliability Coordinator updated the RAS database in accordance with Requirement R9 but was late by more than 90 full calendar days. OR The Reliability Coordinator failed to update the RAS database in accordance with Requirement R9.

D. Regional Variances

None.

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	
0	March 16, 2007	Identified by Commission as "fill-in-the-blank" with no action taken on the standard	
1	November 13, 2014	Adopted by the Board of Trustees	
1	November 19, 2015	Accepted by Commission for informational purposes only	
2	May 5, 2016	Adopted by Board of Trustees	
2	September 20, 2017	FERC Order No. 837 issued approving PRC-012-2	

Attachment 1
Supporting Documentation for RAS Review

The following checklist identifies important Remedial Action Scheme (RAS) information for each new or functionally modified[2] RAS that the RAS-entity must document and provide to the reviewing Reliability Coordinator(s) (RC). If an item on this list does not apply to a specific RAS, a response of "Not Applicable" for that item is appropriate. When RAS are submitted for functional modification review and approval, only the proposed modifications to that RAS require review; however, the RAS-entity must provide a summary of the existing functionality. The RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. Additional entities (without decision authority) may be part of the RAS review process at the request of the RC.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.
2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP.
4. Data to populate the RAS database:
    a. RAS name.
    b. Each RAS-entity and contact information.
    c. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
    d. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
    e. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
    f. Action(s) to be taken by the RAS.
    g. Identification of limited impact[3] RAS.
    h. Any additional explanation relevant to high-level understanding of the RAS.

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[2] Functionally modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[3] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy.
2. The action(s) to be taken by the RAS in response to disturbance conditions.
3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed.
4. Information regarding any future System plans that will impact the RAS.
5. RAS-entity proposal and justification for limited impact designation, if applicable.
6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.
    d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
    e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoid adverse interactions with other RAS, and protection and control systems.
8. Identification of other affected RCs.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.
2. Information on detection logic and settings/parameters that control the operation of the RAS.
3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.
4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective.
5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies RAS information that the RAS-entity shall document and provide to each reviewing RC.

1. Information necessary to ensure that the RC is able to understand the physical and electrical location of the RAS and related facilities.
2. A summary of applicable technical studies and technical justifications upon which the decision to retire the RAS is based.
3. Anticipated date of RAS retirement.

Attachment 2
Reliability Coordinator RAS Review Checklist

The following checklist identifies reliability-related considerations for the Reliability Coordinator (RC) to review and verify for each new or functionally modified[4] Remedial Action Scheme (RAS). The RC review is not limited to the checklist items and the RC may request additional information on any aspect of the RAS as well as any reliability issue related to the RAS. If a checklist item is not relevant to a particular RAS, it should be noted as "Not Applicable." If reliability considerations are identified during the review, the considerations and the proposed resolutions should be documented with the remaining applicable Attachment 2 items.

I. Design

1. The RAS actions satisfy performance objectives for the scope of events and conditions that the RAS is intended to mitigate.
2. The designed timing of RAS operation(s) is appropriate to its BES performance objectives.
3. The RAS arming conditions, if applicable, are appropriate to its System performance objectives.
4. The RAS avoids adverse interactions with other RAS, and protection and control systems.
5. The effects of RAS incorrect operation, including inadvertent operation and failure to operate, have been identified.
6. Determination whether or not the RAS is limited impact.[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.
7. Except for limited impact RAS as determined by the RC, the possible inadvertent operation of the RAS resulting from any single RAS component malfunction satisfies all of the following:
    a. The BES shall remain stable.
    b. Cascading shall not occur.
    c. Applicable Facility Ratings shall not be exceeded.

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[4] Functionally modified: Any modification to a RAS consisting of any of the following:
- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

[5] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.

e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.

8. The effects of future BES modifications on the design and operation of the RAS have been identified, where applicable.

II. Implementation

1. The implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs).
2. Except for limited impact RAS as determined by the RC, a single component failure in a RAS does not prevent the BES from meeting the same performance requirements as those required for the events and conditions for which the RAS is designed.
3. The RAS design facilitates periodic testing and maintenance.
4. The mechanism or procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designed to operate.

III. RAS Retirement

RAS retirement reviews should assure that there is adequate justification for why a RAS is no longer needed.

Attachment 3
Database Information

1. RAS name.
2. Each RAS-entity and contact information.
3. Expected or actual in-service date; most recent RC-approval date (Requirement R3); most recent evaluation date (Requirement R4); and date of retirement, if applicable.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under- or over-voltage, or slow voltage recovery).
5. Description of the Contingencies or System conditions for which the RAS was designed (i.e., initiating conditions).
6. Action(s) to be taken by the RAS.
7. Identification of limited impact[6] RAS.
8. Any additional explanation relevant to high-level understanding of the RAS.

[6] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Technical Justification

4.1.1 Reliability Coordinator

The Reliability Coordinator (RC) is the best-suited functional entity to perform the Remedial Action Scheme (RAS) review because the RC has the widest area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. The Wide Area purview better facilitates the evaluation of interactions among separate RAS, as well as interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator, Transmission Planner, or other entities involved in the planning or implementation of a RAS. The RC is also less likely to be a stakeholder in any given RAS and can therefore maintain objective independence.

4.1.2 Planning Coordinator

The Planning Coordinator (PC) is the best-suited functional entity to perform the RAS evaluation to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, similar to the planning analyses performed by PCs.

4.1.3 RAS-entity

The RAS-entity is any Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS. If all of the RAS (RAS components) have a single owner, then that RAS-entity has sole responsibility for all the activities assigned within the standard to the RAS-entity. If the RAS (RAS components) have more than one owner, then each separate RAS component owner is a RAS-entity and is obligated to participate in various activities identified by the Requirements.

The standard does not stipulate particular compliance methods. RAS-entities have the option of collaborating to fulfill their responsibilities for each applicable requirement. Such collaboration and coordination may promote efficiency in achieving the reliability objectives of the requirements; however, the individual RAS-entity must be able to demonstrate its participation for compliance. As an example, the individual RAS-entities could collaborate to produce and submit a single, coordinated Attachment 1 to the reviewing RC pursuant to Requirement R1 to initiate the RAS review process.

Limited impact

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. These differences in RAS design, action, and risk to the BES are identified and verified within the construct of Requirements R1-R4 of PRC-012-2.

The reviewing RC has the authority to designate a RAS as limited impact if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The reviewing RC makes the final determination as to whether a RAS qualifies for the limited impact designation based upon the studies and other information provided with the Attachment 1 submittal by the RAS-entity.

The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type III classification in NPCC (Northeast Power Coordinating Council) as initially appropriate for limited impact designation. The following information describing the aforementioned WECC and NPCC RAS is excerpted from the respective regional documentation[7].The drafting team notes that the information below represents the state of the WECC and NPCC regional processes at the time of this standard development and is subject to change before the effective date of PRC-012-2.

WECC: Local Area Protection Scheme (LAPS)
A Remedial Action Scheme (RAS) whose failure to operate would NOT result in any of the following:

- Violations of TPL-001-WECC-RBP System Performance RBP,
- Maximum load loss ≥ 300 MW,
- Maximum generation loss ≥ 1000 MW.

NPCC: Type III
An SPS whose misoperation or failure to operate results in no **significant adverse impact** outside the **local area**.

The following terms are also defined by NPCC to assess the impact of the SPS for classification:

Significant adverse impact – With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

a. system instability;
b. unacceptable system dynamic response or equipment tripping;
c. voltage levels in violation of applicable emergency limits;
d. loadings on transmission facilities in violation of applicable emergency limits;
e. unacceptable loss of load.

Local area – An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be

[7] WECC Procedure to Submit a RAS for Assessment Information Required to Assess the Reliability of a RAS Guideline, Revised 10/28/2013 | NPCC Regional Reliability Reference Directory # 7, Special Protection Systems, Version 2, 3/31/2015

relatively small geographically with a relatively large number of buses in a densely networked system.

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC, is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

To propose an existing RAS (a RAS implemented prior to the effective date of PRC-012-2) be designated as limited impact by the reviewing RC, the RAS-entity must prepare and submit the appropriate Attachment 1 information that includes the technical justification (evaluations) documenting that the System can meet the performance requirements (specified in Requirement R4, Parts 4.1.4 and 4.1.5) resulting from a single RAS component malfunction or failure, respectively.

There is nothing that precludes a RAS-entity from working with the reviewing RC during the implementation period of PRC-012-2, in anticipation of the standard becoming enforceable. However, even if the reviewing RC determines the RAS qualifies as limited impact, the designation is not relevant until the standard becomes effective. Until then, the existing regional processes remain in effect as well as the existing RAS classifications or lack thereof.

An example of a scheme that could be recognized as a limited impact RAS is a load shedding or generation rejection scheme used to mitigate the overload of a BES transmission line. The inadvertent operation of such a scheme would cause the loss of either a certain amount of generation or load. The evaluation by the RAS-entity should demonstrate that the loss of this amount of generation or load, without the associated contingency for RAS operation actually occurring, is acceptable and not detrimental to the reliability of BES; e.g., in terms of frequency and voltage stability. The failure of that scheme to operate when intended could potentially lead to the overloading of a transmission line beyond its acceptable rating. The RAS-entity would need to demonstrate that this overload, while in excess of the applicable Facility Rating, is not detrimental to the BES outside the contained area (predetermined by studies) affected by the contingency.

Other examples of limited impact RAS include:

- A scheme used to protect BES equipment from damage caused by overvoltage through generation rejection or equipment tripping.
- A centrally-controlled undervoltage load shedding scheme used to protect a contained area (predetermined by studies) of the BES against voltage collapse.
- A scheme used to trip a generating unit following certain BES Contingencies to prevent the unit from going out of synch with the System; where, if the RAS fails to operate and the unit pulls out of synchronism, the resulting apparent impedance swings do not

result in the tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

Requirement R1

Each RAS is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES); therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification, or retirement (removal from service) must be completed prior to implementation.

Functional modifications consists of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

An example indicating the limits of an in-kind replacement of a RAS component is the replacement of one relay (or other device) with a relay (or other device) that uses similar functions. For instance, if a RAS included a CO-11 relay which was replaced by an IAC-53 relay, that would be an in-kind replacement. If the CO-11 relay were replaced by a microprocessor SEL-451 relay that used only the same functions as the original CO-11 relay, that would also be an in-kind replacement; however, if the SEL-451 relay was used to add new logic to what the CO-11 relay had provided, then the replacement relay would be a functional modification.

Changes to RAS pickup levels that require no other scheme changes are not considered a functional modification. For example, System conditions require a RAS to be armed when the combined flow on two lines exceeds 500 MW. If a periodic evaluation pursuant to Requirement R4, or other assessment, indicates that the arming level should be reduced to 450 MW without requiring any other RAS changes that would not be a functional modification. Similarly, if a RAS is designed to shed load to reduce loading on a particular line below 1000 amps, then a change in the load shedding trigger from 1000 amps to 1100 amps would not be a functional modification.

Another example illustrates a case where a System change may result in a RAS functional change. Assume that a generation center is connected to a load center through two transmission lines. The lines are not rated to accommodate full plant output if one line is out of service, so a RAS monitors the status of both lines and trips or ramps down the generation to a safe level following loss of either line. Later, one of the lines is tapped to serve additional load. The System that the RAS impacts now includes three lines, loss of any of which is likely to still require generation reduction. The modified RAS will need to monitor all three lines (add two line terminal status inputs to the RAS) and the logic to recognize the specific line outages would change, while the generation reduction (RAS output) requirement may or may not change, depending on which line is out of service. These required RAS changes would be a functional modification.

Any functional modification to a RAS will need to be reviewed and approved through the process described in Requirements R1, R2, and R3. The need for such functional modifications may be identified in several ways including but not limited to the Planning evaluations pursuant to R4, incorrect operations pursuant to R5, a test failure pursuant to R8, or Planning assessments related to future additions or modifications of other facilities.

See Item 4a in the Implementation Section of Attachment 1 in the Supplemental Material section for typical RAS components for which a failure may be considered. The RC has the discretion to make the final determination regarding which components should be regarded as RAS components during its review.

To facilitate a review that promotes reliability, the RAS-entity(ies) must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity(ies) provide them to the reviewing Reliability Coordinator (RC). The RC that coordinates the area where the RAS is located is responsible for the review. In cases where a RAS crosses multiple RC Area boundaries, each affected RC is responsible for conducting either individual reviews or a coordinated review.

Requirement R1 does not specify how far in advance of implementation the RAS-entity(ies) must provide Attachment 1 data to the reviewing RC. The information will need to be submitted early enough to allow RC review in the allotted time pursuant to Requirement R2, including resolution of any reliability issues that might be identified, in order to obtain approval of the reviewing RC. Expeditious submittal of this information is in the interest of each RAS-entity to effect a timely implementation.

Requirement R2

Requirement R2 mandates that the RC perform reviews of all proposed new RAS and existing RAS proposed for functional modification, or retirement (removal from service) in its RC Area.

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the BES, if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue, or achieve an economic or operational advantage, and could introduce reliability risks that might not be apparent to a RAS-entity(ies). An independent review by a multi-disciplinary panel of subject matter experts with planning, operations, protection, telecommunications, and equipment expertise is an effective means of identifying risks and recommending RAS modifications when necessary.

The RC is the functional entity best suited to perform the RAS reviews because it has the widest area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among the RAS and other protection and control systems.

The selection of the RC also minimizes the possibility of a "conflict of interest" that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC may request assistance in RAS reviews from other parties such as the PC(s) or regional technical groups (e.g., Regional Entities); however, the RC retains responsibility for compliance with the requirement. It is recognized that the RC does not possesses more information or ability than anticipated by their functional registration as designated by NERC. The NERC Functional Model is a guideline for the development of standards and their applicability and does not contain compliance requirements. If Reliability Standards address functions that are not described in the model, the Reliability Standard requirements take precedence over the Functional Model. For further reference, please see the Introduction section of NERC's Reliability Functional Model, Version 5, November 2009. Attachment 2 of this standard is a checklist for assisting the RC in identifying design and implementation aspects of a RAS, and for facilitating consistent reviews of each RAS submitted for review. The time frame of four full calendar months is consistent with current utility practice; however, flexibility is provided by allowing the parties to negotiate a different schedule for the review. Note, an RC may need to include this task in its reliability plan(s) for the NERC Region(s) in which it is located.

Requirement R3

Requirement R3 mandates that each RAS-entity resolve all reliability issues (pertaining to its RAS) identified during the RAS review by the reviewing Reliability Coordinators. Examples of reliability issues include a lack of dependability, security, or coordination. RC approval of a RAS is considered to be obtained when the reviewing RC's feedback to each RAS-entity indicates that either no reliability issues were identified during the review or all identified reliability issues were resolved to the RC's satisfaction.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If a RAS is installed to meet performance requirements of NERC Reliability Standards, a failure of the RAS to operate when intended would put the System at risk of violating NERC Reliability Standards if specified Contingency(ies) or System conditions occur. This risk is mitigated by designing the RAS so that it will accomplish the intended purpose while experiencing a single RAS component failure. This is often accomplished through redundancy. Other strategies for providing dependability include "over-tripping" load or generation, or alternative automatic backup schemes.

Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. False or inadvertent operation of a RAS results in taking a programmed action without the appropriate arming conditions, occurrence of specified Contingency(ies), or System conditions expected to trigger the RAS action. Typical RAS actions include shedding load or generation or re-configuring the System. Such actions, if inadvertently taken, are undesirable and may put the System in a less secure state. Worst case impacts from inadvertent operation often occur if all programmed RAS actions occur. If the System performance still satisfies PRC-012-2 Requirement R4, Part 4.3, no additional mitigation is required. Security enhancements to the RAS design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Any reliability issue identified during the review must be resolved before implementing the RAS to avoid placing the System at unacceptable risk. The RAS-entity or the reviewing RC(s) may have alternative ideas or methods available to resolve the issue(s). In either case, the concern needs to be resolved in deference to reliability, and the RC has the final decision.

A specific time period for the RAS-entity to respond to the RC(s) review is not necessary because an expeditious response is in the interest of each RAS-entity to effect a timely implementation.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Requirement R4

Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of a periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that requirements for BES performance following inadvertent RAS operation and single component failure continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it interacts with and impacts the BES.

A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability.

A RAS implemented after the effective date of this standard can only be designated as limited impact by the reviewing RC(s). A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

Requirement R4 also clarifies that the RAS single component failure and inadvertent operation tests do not apply to RAS which are determined to be limited impact. Requiring a limited impact RAS to meet the single component failure and inadvertent operation tests would just add complexity to the design with little or no improvement in the reliability of the BES.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The PC is the functional entity best suited to perform the analyses because they have a wide-area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The intent of Requirement R4, Part 4.1.4 is to verify that the possible inadvertent operation of the RAS (other than limited impact RAS), caused by the malfunction of a single component of the RAS, meet the same System performance requirements as those required for the Contingency(ies) or System conditions for which it is designed. If the RAS is designed to meet one of the planning events (P0-P7) in TPL-001-4, the possible inadvertent operation of the RAS must meet the same performance requirements listed in the standard for that planning event. The requirement clarifies that the inadvertent operation to be considered is only that caused by the malfunction of a single RAS component. This allows features to be designed into the RAS to improve security, such that inadvertent operation due to malfunction of a single component is prevented; otherwise, the RAS inadvertent operation must satisfy Requirement R4, Part 4.1.4.

The intent of Requirement R4, Part 4.1.4 is also to verify that the possible inadvertent operation of the RAS (other than limited impact RAS) installed for an extreme event in TPL-001-4 or for some other Contingency or System conditions not defined in TPL-001-4 (therefore without performance requirements), meet the minimum System performance requirements of Category P7 in Table 1 of NERC Reliability Standard TPL-001-4. However, instead of referring to the TPL standard, the requirement lists the System performance requirements that a potential inadvertent operation must satisfy. The performance requirements listed (Requirement R4, Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events (P0-P7) listed in TPL-001-4.

With reference to Requirement 4, Part 4.1.4, note that the only differences in performance requirements among the TPL (P0-P7) events (not common to all of them) concern Non-Consequential Load Loss and interruption of Firm Transmission Service. It is not necessary for Requirement R4, Part 4.1.4 to specify performance requirements related to these areas because a RAS is only allowed to drop non-consequential load or interrupt Firm Transmission Service if that action is allowed for the Contingency for which it is designed. Therefore, the inadvertent operation should automatically meet Non-Consequential Load Loss or interrupting Firm Transmission Service performance requirements for the Contingency(ies) for which it was designed.

The intent of Requirement R4, Part 4.1.5 is to verify that a single component failure in a RAS, other than limited impact RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. This analysis is needed to ensure that changing System conditions do not result in the single component failure requirement not being met.

The following is an example of a single component failure causing the System to fail to meet the performance requirements for the P1 event for which the RAS was installed. Consider the instance where a three-phase Fault (P1 event) results in a generating plant becoming unstable (a violation of the System performance requirements of TPL-001-4). To resolve this, a RAS is installed to trip a single generating unit which allows the remaining units at the plant to remain stable. If failure of a single component (e.g., relay) in the RAS results in the RAS failing to operate for the P1 event, the generating plant would become unstable (failing to meet the System performance requirements of TPL-001-4 for a P1 event).

Requirement R4, Part 4.1.5 does not mandate that all RAS have redundant components. For example:

- Consider the instance where a RAS is installed to mitigate an extreme event in TPL-001-4. There are no System performance requirements for extreme events; therefore, the RAS does not need redundancy to meet the same performance requirements as those required for the events and conditions for which the RAS was designed.

- Consider a RAS that arms more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

The scope of the periodic evaluation does not include a new review of the physical implementation of the RAS, as this was confirmed by the RC during the initial review and verified by subsequent functional testing. However, it is possible that a RAS design which previously satisfied requirements for inadvertent RAS operation and single component failure by means other than component redundancy may fail to satisfy these requirements at a later time, and must be evaluated with respect to the current System. For example, if the actions of a particular RAS include tripping load, load growth could occur over time that impacts the amount of load to be tripped. These changes could result in tripping too much load upon inadvertent operation and result in violations of Facility Ratings. Alternatively, the RAS might be designed to trip more load than necessary (i.e., “over trip”) in order to satisfy single component failure requirements. System changes could result in too little load being tripped and unacceptable BES performance if one of the loads failed to trip.

Requirement R5

The correct operation of a RAS is important to maintain the reliability and integrity of the BES. Any incorrect operation of a RAS indicates the RAS effectiveness and/or coordination may have been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: (1) verify RAS operation is consistent with implemented design; or (2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation; however, flexibility is provided by allowing the parties to negotiate a different schedule for the analysis. To promote reliability, the RAS-entity(s) is required to provide the results of RAS operational performance analyses to its reviewing RC(s) if the analyses revealed a deficiency.

The RAS-entity(ies) may need to collaborate with its associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Requirement R6

RAS deficiencies potentially pose a reliability risk to the BES. RAS deficiencies may be identified in the periodic RAS evaluation conducted by the PC in Requirement R4, in the operational analysis conducted by the RAS-entity in Requirement R5, or in the functional test performed by the RAS-entity(ies) in Requirement R8. To mitigate potential reliability risks, Requirement R6 mandates that each RAS-entity participate in developing a CAP that establishes the mitigation actions and timetable necessary to address the deficiency.

The RAS-entity(ies) that owns the RAS components, is responsible for the RAS equipment, and is in the best position to develop the timelines and perform the necessary work to correct RAS deficiencies. If necessary, the RAS-entity(ies) may request assistance with development of the CAP from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

A CAP may require functional changes be made to a RAS. In this case, Attachment 1 information must be submitted to the reviewing RC(s), an RC review must be performed to obtain RC approval before the RAS-entity can place RAS modifications in service, per Requirements R1, R2, and R3.

Depending on the complexity of the issues, development of a CAP may require study, engineering or consulting work. A timeframe of six full calendar months is allotted to allow enough time for RAS-entity collaboration on the CAP development, while ensuring that deficiencies are addressed in a reasonable time. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the RAS deficiency is resolved. The possibility of such operating restrictions will incent the RAS-entity to resolve the issue as quickly as possible.

The following are example situations of when a CAP is required:

- A determination after a RAS operation/non-operation investigation that the RAS did not meet performance expectations or did not operate as designed.
- Periodic planning assessment reveals RAS changes are necessary to correct performance or coordination issues.
- Equipment failures.
- Functional testing identifies that a RAS is not operating as designed.

Requirement R7

Requirement R7 mandates that each RAS-entity implement its CAP developed in Requirement R6 which mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the RAS-entity must notify the reviewing Reliability

Coordinator(s). The RAS-entity must also notify the Reliability Coordinator(s) when the CAP has been completed.

The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. A RAS deficiency may require the RC or Transmission Operator to impose operating restrictions so the System can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions will incent the RAS-entity to complete the CAP as quickly as possible.

Requirement R8

The reliability objective of Requirement R8 is to test the non-Protection System components of a RAS (controllers such as programmable logic controllers (PLCs)) and to verify the overall performance of the RAS through functional testing. Functional tests validate RAS operation by ensuring System states are detected and processed, and that actions taken by the controls are correct and occur within the expected time using the in-service settings and logic. Functional testing is aimed at assuring overall RAS performance and not the component focused testing contained in the PRC-005 maintenance standard.

Since the functional test operates the RAS under controlled conditions with known System states and expected results, testing and analysis can be performed with minimum impact to the BES and should align with expected results. The RAS-entity is in the best position to determine the testing procedure and schedule due to their overall knowledge of the RAS design, installation, and functionality. Periodic testing provides the RAS-entity assurance that latent failures may be identified and also promotes identification of changes in the System that may have introduced latent failures.

The six and twelve full calendar year functional testing intervals are greater than the annual or bi-annual periodic testing performed in some NERC Regions. However, these intervals are a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for limited impact RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the Bulk Power System.

Functional testing is not synonymous with end-to-end testing. End-to-end testing is an acceptable method but may not be feasible for many RAS. When end-to-end testing is not possible, a RAS-entity may use a segmented functional testing approach. The segments can be tested individually negating the need for complex maintenance schedules. In addition, actual RAS operation(s) can be used to fulfill the functional testing requirement. If a RAS does not operate in its entirety during a System event or System conditions do not allow an end-to-end scheme test, then the segmented approach should be used to fulfill this Requirement. Functional testing includes the testing of all RAS inputs used for detection, arming, operating, and data collection. Functional testing, by default operates the processing logic and infrastructure of a RAS, but focuses on the RAS inputs as well as the actions initiated by RAS outputs to address the System condition(s) for which the RAS is designed. All segments and components of a RAS must be tested or have proven operations within the applicable maximum test interval to demonstrate compliance with the Requirement.

As an example of segment testing, consider a RAS controller implemented using a PLC that receives System data, such as loading or line status, from distributed devices. These distributed devices could include meters, protective relays, or other PLCs. In this example RAS, a line protective relay is used to provide an analog metering quantity to the RAS control PLC. A functional test would verify that the System data is received from the protective relay by the PLC, processed by the PLC, and that PLC outputs are appropriate. There is no need to verify the protective relay's ability to measure the power system quantities, as this is a requirement for Protection Systems used as RAS in PRC-005, Table 1-1, Component Type – Protective Relay. Rather the functional test is focused on the use of the protective relay data at the PLC, including the communications data path from relay to PLC if this data is essential for proper RAS operation. Additionally, if the control signal back to the protective relay is also critical to the proper functioning of this example RAS, then that path is also verified up to the protective relay. This example describes a test for one segment of a RAS which verifies RAS action, verifies PLC control logic, and verifies RAS communications.

IEEE C37.233, "IEEE Guide for Power System Protection Testing," 2009 section 8 (particularly 8.3-8.5), provides an overview of functional testing. The following opens section 8.3:

> Proper implementation requires a well-defined and coordinated test plan for performance evaluation of the overall system during agreed maintenance intervals. The maintenance test plan, also referred to as functional system testing, should include inputs, outputs, communication, logic, and throughput timing tests. The functional tests are generally not component-level testing, rather overall system testing. Some of the input tests may need to be done ahead of overall system testing to the extent that the tests affect the overall performance. The test coordinator or coordinators need to have full knowledge of the intent of the scheme, isolation points, simulation scenarios, and restoration to normal procedures.
>
> The concept is to validate the overall performance of the scheme, including the logic where applicable, to validate the overall throughput times against system modeling for different types of Contingencies, and to verify scheme performance as well as the inputs and outputs.

If a RAS passes a functional test, it is not necessary to provide that specific information to the RC because that is the expected result and requires no further action. If a segment of a RAS fails a functional test, the status of that degraded RAS is required to be reported (in Real-time) to the Transmission Operator via PRC-001, Requirement R6, then to the RC via TOP-001-3, Requirement R8. See Phase 2 of Project 2007-06 for the mapping document from PRC-001 to other standards regarding notification of RC by TOP if a deficiency is found during testing. Consequently, it is not necessary to include a similar requirement in this standard.

The initial test interval begins on the effective date of the standard pursuant to the implementation plan. Subsequently, the maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A RAS-entity may choose to count a correct RAS operation as a qualifying functional test for those RAS segments which operate. If a System event causes a correct, but partial RAS operation, separate functional tests of the segments that did not operate are still required within the maximum test interval that started on the date of the previous successful test of those (non-operating) segments in order to be compliant with Requirement R8.

Requirement R9

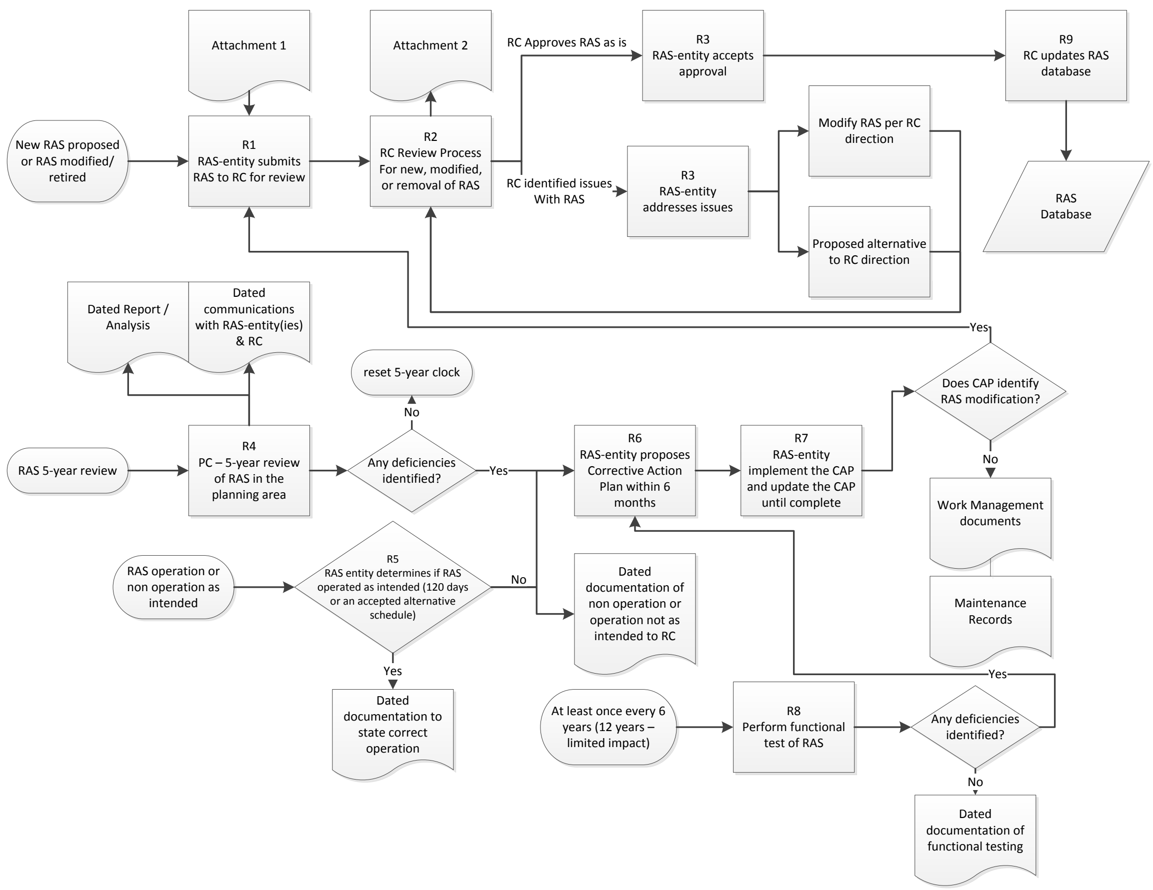
The RAS database required to be maintained by the RC in Requirement R9 ensures information regarding existing RAS is available. Attachment 3 contains the minimum information that is required to be included about each RAS listed in the database. Additional information can be requested by the RC.

The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. The information provided is sufficient for an entity with a reliability need to evaluate whether the RAS can impact its System. For example, a RAS performing generation rejection to mitigate an overload on a transmission line may cause a power flow change within an adjacent entity area. This entity should be able to evaluate the risk that a RAS poses to its System from the high-level information provided in the RAS database.

The RAS database does not need to list detailed settings or modeling information, but the description of the System performance issues, System conditions, and the intended corrective actions must be included. If additional details about the RAS operation are required, the entity may obtain the contact information of the RAS-entity from the RC.

Process Flow Diagram

The diagram below depicts the process flow of the PRC-012-2 requirements.



Technical Justifications for Attachment 1 Content
Supporting Documentation for RAS Review

To perform an adequate review of the expected reliability implications of a Remedial Action Scheme (RAS), it is necessary for the RAS-entity(ies) to provide a detailed list of information describing the RAS to the reviewing RC. If there are multiple RAS-entities for a single RAS, information will be needed from all RAS-entities. Ideally, in such cases, a single RAS-entity will take the lead to compile all the data identified into a single Attachment 1.

The necessary data ranges from a general overview of the RAS to summarized results of transmission planning studies, to information about hardware used to implement the RAS. Coordination between the RAS and other RAS and protection and control systems will be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the RAS.

Attachment 1

The following checklist identifies important RAS information for each new or functionally modified[8] RAS that the RAS-entity shall document and provide to the RC for review pursuant to Requirement R1. When a RAS has been previously reviewed, only the proposed modifications to that RAS require review; however, it will be helpful to each reviewing RC if the RAS-entity provides a summary of the existing RAS functionality.

I. General

1. Information such as maps, one-line drawings, substation and schematic drawings that identify the physical and electrical location of the RAS and related facilities.

   Provide a description of the RAS to give an overall understanding of the functionality and a map showing the location of the RAS. Identify other protection and control systems requiring coordination with the RAS. See RAS Design below for additional information.

   Provide a single-line drawing(s) showing all sites involved. The drawing(s) should provide sufficient information to allow the RC review team to assess design reliability, and should include information such as the bus arrangement, circuit breakers, the associated switches, etc. For each site, indicate whether detection, logic, action, or a combination of these is present.

[8] Functionally modified: Any modification to a RAS consisting of any of the following:

- Changes to System conditions or contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

2. Functionality of new RAS or proposed functional modifications to existing RAS and documentation of the pre- and post-modified functionality of the RAS.
3. The Corrective Action Plan (CAP) if RAS modifications are proposed in a CAP. [Reference NERC Reliability Standard PRC-012-2, Requirements R5 and R7]

   Provide a description of any functional modifications to a RAS that are part of a CAP that are proposed to address performance deficiency(ies) identified in the periodic evaluation pursuant to Requirement R4, the analysis of an actual RAS operation pursuant to Requirement R5, or functional test failure pursuant to Requirement R8. A copy of the most recent CAP must be submitted in addition to the other data specified in Attachment 1.
4. Initial data to populate the RAS database.
   a. RAS name.
   b. Each RAS-entity and contact information.
   c. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.
   d. System performance issue or reason for installing the RAS (*e.g.*, thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
   e. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
   f. Corrective action taken by the RAS.
   g. Identification of limited impact[9] RAS.
   h. Any additional explanation relevant to high level understanding of the RAS.

      Note: This is the same information as is identified in Attachment 3. Supplying the data at this point in the review process ensures a more complete review and minimizes any administrative burden on the reviewing RC(s).

II. Functional Description and Transmission Planning Information

1. Contingencies and System conditions that the RAS is intended to remedy. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.1]
   a. The System conditions that would result if no RAS action occurred should be identified.

[9] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

   b. Include a description of the System conditions that should arm the RAS so as to be ready to take action upon subsequent occurrence of the critical System Contingencies or other operating conditions when RAS action is intended to occur. If no arming conditions are required, this should also be stated.

   c. Event-based RAS are triggered by specific Contingencies that initiate mitigating action. Condition-based RAS may also be initiated by specific Contingencies, but specific Contingencies are not always required. These triggering Contingencies and/or conditions should be identified.

2. The actions to be taken by the RAS in response to disturbance conditions. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.2]

   Mitigating actions are designed to result in acceptable System performance. These actions should be identified, including any time constraints and/or "backup" mitigating measures that may be required in case of a single RAS component failure.

3. A summary of technical studies, if applicable, demonstrating that the proposed RAS actions satisfy System performance objectives for the scope of System events and conditions that the RAS is intended to remedy. The technical studies summary shall also include information such as the study year(s), System conditions, and Contingencies analyzed on which the RAS design is based, and the date those technical studies were performed. [Reference NEC Reliability Standard PRC-014, R3.2]

   Review the scheme purpose and impact to ensure it is (still) necessary, serves the intended purposes, and meets current performance requirements. While copies of the full, detailed studies may not be necessary, any abbreviated descriptions of the studies must be detailed enough to allow the reviewing RC(s) to be convinced of the need for the scheme and the results of RAS-related operations.

4. Information regarding any future System plans that will impact the RAS. [Reference NERC Reliability Standard PRC-014, R3.2]

   The RC's other responsibilities under the NERC Reliability Standards focus on the Operating Horizon, rather than the Planning Horizon. As such, the RC is less likely to be aware of any longer range plans that may have an impact on the proposed RAS. Such knowledge of future Plans is helpful to provide perspective on the capabilities of the RAS.

5. RAS-entity proposal and justification for limited impact designation, if applicable.

   A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type 3 in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

6. Documentation describing the System performance resulting from the possible inadvertent operation of the RAS, except for limited impact RAS, caused by any single RAS component malfunction. Single component malfunctions in a RAS not determined to be limited impact must satisfy all of the following:
   [Reference NERC Reliability Standard PRC-012, R1.4]
   a. The BES shall remain stable.
   b. Cascading shall not occur.
   c. Applicable Facility Ratings shall not be exceeded.
   d. BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits as established by the Transmission Planner and the Planning Coordinator.
   e. Transient voltage responses shall be within acceptable limits as established by the Transmission Planner and the Planning Coordinator.
7. An evaluation indicating that the RAS settings and operation avoids adverse interactions with other RAS, and protection and control systems.
   [Reference NERC Reliability Standards PRC-012, R1.5 and PRC-014, R3.4]

   RAS are complex schemes that may take action such as tripping load or generation or re-configuring the System. Many RAS depend on sensing specific System configurations to determine whether they need to arm or take actions. An examples of an adverse interaction: A RAS that reconfigures the System also changes the available Fault duty, which can affect distance relay overcurrent ("fault detector") supervision and ground overcurrent protection coordination.
8. Identification of other affected RCs.

   This information is needed to aid in information exchange among all affected entities and coordination of the RAS with other RAS and protection and control systems.

III. Implementation

1. Documentation describing the applicable equipment used for detection, dc supply, communications, transfer trip, logic processing, control actions, and monitoring.

   Detection
   Detection and initiating devices, whether for arming or triggering action, should be designed to be secure. Several types of devices have been commonly used as disturbance, condition, or status detectors:

   - Line open status (event detectors),
   - Protective relay inputs and outputs (event and parameter detectors),
   - Transducer and IED (analog) inputs (parameter and response detectors),
   - Rate of change (parameter and response detectors).

   DC Supply

Batteries and charges, or other forms of dc supply for RAS, are commonly also used for Protection Systems. This is acceptable, and maintenance of such supplies is covered by PRC-005. However, redundant RAS, when used, should be supplied from separately protected (fused or breakered) circuits.

Communications: Telecommunications Channels
Telecommunications channels used for sending and receiving RAS information between sites and/or transfer trip devices should meet at least the same criteria as other relaying protection communication channels. Discuss performance of any non-deterministic communication systems used (such as Ethernet).

The scheme logic should be designed so that loss of the channel, noise, or other channel or equipment failure will not result in a false operation of the scheme.

It is highly desirable that the channel equipment and communications media (power line carrier, microwave, optical fiber, etc.) be owned and maintained by the RAS-entity, or perhaps leased from another entity familiar with the necessary reliability requirements. All channel equipment should be monitored and alarmed to the dispatch center so that timely diagnostic and repair action shall take place upon failure. Publicly switched telephone networks are generally an undesirable option.

Communication channels should be well labeled or identified so that the personnel working on the channel can readily identify the proper circuit. Channels between entities should be identified with a common name at all terminals.

Transfer Trip
Transfer trip equipment, when separate from other RAS equipment, should be monitored and labeled similarly to the channel equipment.

Logic Processing
All RAS require some form of logic processing to determine the action to take when the scheme is triggered. Required actions are always scheme dependent. Different actions may be required at different arming levels or for different Contingencies. Scheme logic may be achievable by something as simple as wiring a few auxiliary relay contacts or by much more complex logic processing.

Platforms that have been used reliably and successfully include PLCs in various forms, personal computers (PCs), microprocessor protective relays, remote terminal units (RTUs), and logic processors. Single-function relays have been used historically to implement RAS, but this approach is now less common except for very simple new RAS or minor additions to existing RAS.

Control Actions
RAS action devices may include a variety of equipment such as transfer trip, protective relays, and other control devices. These devices receive commands from the logic processing function (perhaps through telecommunication facilities) and initiate RAS actions at the sites where action is required.

Monitoring by SCADA/EMS should include at least

- Whether the scheme is in service or out of service.
  - For RAS that are armed manually, the arming status may be the same as whether the RAS is in service or out of service.

  - For RAS that are armed automatically, these two states are independent because a RAS that has been placed in service may be armed or unarmed based on whether the automatic arming criteria have been met.

- The current operational state of the scheme (available or not).
- In cases where the RAS requires single component failure performance; e.g., redundancy, the minimal status indications should be provided separately for each RAS.

  - The minimum status is generally sufficient for operational purposes; however, where possible it is often useful to provide additional information regarding partial failures or the status of critical components to allow the RAS-entity to more efficiently troubleshoot a reported failure. Whether this capability exists will depend in part on the design and vintage of equipment used in the RAS. While all schemes should provide the minimum level of monitoring, new schemes should be designed with the objective of providing monitoring at least similar to what is provided for microprocessor-based Protection Systems.

2. Information on detection logic and settings/parameters that control the operation of the RAS. [Reference NERC Reliability Standards PRC-012, R1.2 and PRC-013, R1.3]

   Several methods to determine line or other equipment status are in common use, often in combination:

   a. Auxiliary switch contacts from circuit breakers and disconnect switches (52a/b, 89a/b)—the most common status monitor; “a” contacts exactly emulate actual breaker status, while “b” contacts are opposite to the status of the breaker;
   b. Undercurrent detection—a low level indicates an open condition, including at the far end of a line; pickup is typically slightly above the total line-charging current;
   c. Breaker trip coil current monitoring—typically used when high-speed RAS response is required, but usually in combination with auxiliary switch contacts and/or other detection because the trip coil current ceases when the breaker opens; and
   d. Other detectors such as angle, voltage, power, frequency, rate of change of the aforementioned, out of step, etc. are dependent on specific scheme requirements, but some forms may substitute for or enhance other monitoring described in items ‘a’, ‘b’, and ‘c’ above.

   Both RAS arming and action triggers often require monitoring of analog quantities such as power, current, and voltage at one or more locations and are set to detect a specific level of the pertinent quantity. These monitors may be relays, meters, transducers, or other devices

3. Documentation showing that any multifunction device used to perform RAS function(s), in addition to other functions such as protective relaying or SCADA, does not compromise the reliability of the RAS when the device is not in service or is being maintained.

In this context, a multifunction device (e.g., microprocessor-based relay) is a single component that is used to perform the function of a RAS in addition to protective relaying and/or SCADA simultaneously. It is important that other applications in the multifunction device do not compromise the functionality of the RAS when the device is in service or when it is being maintained. The following list outlines considerations when the RAS function is applied in the same microprocessor-based relay as equipment protection functions:

a. Describe how the multifunction device is applied in the RAS.

b. Show the general arrangement and describe how the multi-function device is labeled in the design and application, so as to identify the RAS and other device functions.

c. Describe the procedures used to isolate the RAS function from other functions in the device.

d. Describe the procedures used when each multifunction device is removed from service and whether coordination with other protection schemes is required.

e. Describe how each multifunction device is tested, both for commissioning and during periodic maintenance testing, with regard to each function of the device.

f. Describe how overall periodic RAS functional and throughput tests are performed if multifunction devices are used for both local protection and RAS.

g. Describe how upgrades to the multifunction device, such as firmware upgrades, are accomplished. How is the RAS function taken into consideration?

Other devices that are usually not considered multifunction devices such as auxiliary relays, control switches, and instrument transformers may serve multiple purposes such as protection and RAS. Similar concerns apply for these applications as noted above.

4. Documentation describing the System performance resulting from a single component failure in the RAS, except for limited impact RAS, when the RAS is intended to operate. A single component failure in a RAS not determined to be limited impact must not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed. The documentation should describe or illustrate how the design achieves this objective. [Reference NERC Reliability Standard PRC-012, R1.3]

   RAS automatic arming, if applicable, is vital to RAS and System performance and is therefore included in this requirement.

   Acceptable methods to achieve this objective include, but are not limited to the following:

   a. Providing redundancy of RAS components. Typical examples are listed below:

      i. Protective or auxiliary relays used by the RAS.

ii. Communications systems necessary for correct operation of the RAS.

iii. Sensing devices used to measure electrical or other quantities used by the RAS.

iv. Station dc supply associated with RAS functions.

v. Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices.

vi. Logic processing devices that accept System inputs from RAS components or other sources, make decisions based on those inputs, or initiate output signals to take remedial actions.

b. Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation due to that single component failure will still result in satisfactory System performance, as long as tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.

c. Using alternative automatic actions to back up failures of single RAS components.

d. Manual backup operations, using planned System adjustments such as Transmission configuration changes and re-dispatch of generation, if such adjustments are executable within the time duration applicable to the Facility Ratings.

5. Documentation describing the functional testing process.

IV. RAS Retirement

The following checklist identifies important RAS information for each existing RAS to be retired that the RAS-entity shall document and provide to the Reliability Coordinator for review pursuant to Requirement R1.

1. Information necessary to ensure that the Reliability Coordinator is able to understand the physical and electrical location of the RAS and related facilities.

2. A summary of technical studies and technical justifications, if applicable, upon which the decision to retire the RAS is based.

3. Anticipated date of RAS retirement.

   While the documentation necessary to evaluate RAS removals is not as extensive as for new or functionally modified RAS, it is still vital that, when the RAS is no longer available, System performance will still meet the appropriate (usually TPL) requirements for the Contingencies or System conditions that the RAS had been installed to remediate.

Technical Justification for Attachment 2 Content

Reliability Coordinator RAS Review Checklist

Attachment 2 is a checklist provided to facilitate consistent reviews continent-wide for new or functionally modified RAS prior to the RAS installation. The checklist is meant to assist the RC in identifying reliability-related considerations relevant to various aspects of RAS design and implementation.

Technical Justifications for Attachment 3 Content

Database Information

Attachment 3 contains the minimum information that the RC must consolidate into its database for each RAS in its area.

1. RAS name.
    - The name used to identify the RAS.
2. Each RAS-entity and contact information.
    - A reliable phone number or email address should be included to contact each RAS-entity if more information is needed.
3. Expected or actual in-service date; most recent (Requirement R3) RC-approval date; most recent five full calendar year (Requirement R4) evaluation date; and, date of retirement, if applicable.
    - Specify each applicable date.
4. System performance issue or reason for installing the RAS (e.g., thermal overload, angular instability, poor oscillation damping, voltage instability, under-/over-voltage, slow voltage recovery).
    - A short description of the reason for installing the RAS is sufficient, as long as the main System issues addressed by the RAS can be identified by someone with a reliability need.
5. Description of the Contingencies or System conditions for which the RAS was designed (initiating conditions).
    - A high level summary of the conditions/Contingencies is expected. Not all combinations of conditions are required to be listed.
6. Corrective action taken by the RAS.
    - A short description of the actions should be given. For schemes shedding load or generation, the maximum amount of megawatts should be included.

7. Identification of limited impact[10] RAS.
    - Specify whether or not the RAS is designated as limited impact.
8. Any additional explanation relevant to high-level understanding of the RAS.
    - If deemed necessary, any additional information can be included in this section, but is not mandatory.

[10] A RAS designated as limited impact cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.

Rationale

Rationale for Requirement R1: Each Remedial Action Scheme (RAS) is unique and its action(s) can have a significant impact on the reliability and integrity of the Bulk Electric System (BES). Therefore, a review of a proposed new RAS or an existing RAS proposed for functional modification or retirement; i.e., removal from service must be completed prior to implementation or retirement.

Functional modifications consist of any of the following:

- Changes to System conditions or Contingencies monitored by the RAS
- Changes to the actions the RAS is designed to initiate
- Changes to RAS hardware beyond in-kind replacement; i.e., match the original functionality of existing components
- Changes to RAS logic beyond correcting existing errors
- Changes to redundancy levels; i.e., addition or removal

To facilitate a review that promotes reliability, the RAS-entity must provide the reviewer with sufficient details of the RAS design, function, and operation. This data and supporting documentation are identified in Attachment 1 of this standard, and Requirement R1 mandates that the RAS-entity provide them to the reviewing Reliability Coordinator (RC). The RC (reviewing RC) that coordinates the area where the RAS is located is responsible for the review. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate and submit a single, coordinated Attachment 1 to the reviewing RC. In cases where a RAS crosses RC Area boundaries, each affected RC is responsible for conducting either individual reviews or participating in a coordinated review.

Rationale for Requirement R2: The RC is the functional entity best suited to perform the RAS review because it has the widest area operational and reliability perspective of all functional entities and an awareness of reliability issues in any neighboring RC Area. This Wide Area purview facilitates the evaluation of interactions among separate RAS as well as interactions among RAS and other protection and control systems. Review by the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, Planning Coordinator (PC), Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is not expected to possess more information or ability than anticipated by their functional registration as designated by NERC. The RC may request assistance to perform RAS reviews from other parties such as the PC or regional technical groups; however, the RC will retain the responsibility for compliance with this requirement.

Attachment 2 of this standard is a checklist the RC can use to identify design and implementation aspects of RAS and facilitate consistent reviews for each submitted RAS. The time frame of four full calendar months is consistent with current utility and regional practice;

however, flexibility is provided by allowing the RC(s) and RAS-entity(ies) to negotiate a mutually agreed upon schedule for the review.

Note: An RC may need to include this task in its reliability plan(s) for the NERC Regions(s) in which it is located.

Rationale for Requirement R3: The RC review is intended to identify reliability issues that must be resolved before the RAS can be put in service. Examples of reliability issues include a lack of dependability, security, or coordination.

A specific time period for the RAS-entity to respond to the reviewing RC following identification of any reliability issue(s) is not necessary because the RAS-entity wants to expedite the timely approval and subsequent implementation of the RAS.

A specific time period for the RC to respond to the RAS-entity following the RAS review is also not necessary because the RC will be aware of (1) any reliability issues associated with the RAS not being in service and (2) the RAS-entity's schedule to implement the RAS to address those reliability issues. Since the RC is the ultimate arbiter of BES operating reliability, resolving reliability issues is a priority for the RC and serves as an incentive to expeditiously respond to the RAS-entity.

Rationale for Requirement R4: Requirement R4 mandates that an evaluation of each RAS be performed at least once every five full calendar years. The purpose of the periodic RAS evaluation is to verify the continued effectiveness and coordination of the RAS, as well as to verify that, if a RAS single component malfunction or single component failure were to occur, the requirements for BES performance would continue to be satisfied. A periodic evaluation is required because changes in System topology or operating conditions may change the effectiveness of a RAS or the way it impacts the BES.

RAS are unique and customized assemblages of protection and control equipment that vary in complexity and impact on the reliability of the BES. In recognition of these differences, RAS can be designated by the reviewing RC(s) as limited impact. A limited impact RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. The "BES" qualifier in the preceding statement modifies all of the conditions that follow it. Limited impact RAS are not subject to the RAS single component malfunction and failure tests of Parts 4.1.4 and 4.1.5, respectively. Requiring a limited impact RAS to meet these tests would add complexity to the design with minimal benefit to BES reliability. See the Supplemental Material for more on the limited impact designation.

The standard recognizes the Local Area Protection Scheme (LAPS) classification in WECC (Western Electricity Coordinating Council) and the Type III classification in NPCC (Northeast Power Coordinating Council) as initially appropriate for limited impact designation. A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review processes of WECC or NPCC and is classified as either a Local Area Protection Scheme (LAPS) in WECC or a Type III in NPCC is recognized as a limited impact RAS upon the effective date of PRC-012-2 for the purposes of this standard and is subject to all applicable requirements.

For existing RAS, the initial performance of Requirement R4 must be completed within five full calendar years of the effective date of PRC-012-2. For new or functionally modified RAS, the initial performance of the requirement must be completed within five full calendar years of the RAS approval date by the reviewing RC(s). Five full calendar years was selected as the maximum time frame between evaluations based on the time frames for similar requirements in Reliability Standards PRC-006, PRC-010, and PRC-014. The RAS evaluation can be performed sooner if it is determined that material changes to System topology or System operating conditions could potentially impact the effectiveness or coordination of the RAS. System changes also have the potential to alter the reliability impact of limited impact RAS on the BES. Requirement 4, Part 4.1.3 explicitly requires the periodic evaluation of limited impact RAS to verify the limited impact designation remains applicable; the PC can use its discretion as to how this evaluation is performed. The periodic RAS evaluation will typically lead to one of the following outcomes: 1) affirmation that the existing RAS is effective; 2) identification of changes needed to the existing RAS; or, 3) justification for RAS retirement.

The items required to be addressed in the evaluations (Requirement R4, Parts 4.1.1 through 4.1.5) are planning analyses that may involve modeling of the interconnected transmission system to assess BES performance. The Planning Coordinator (PC) is the functional entity best suited to perform this evaluation because they have a wide area planning perspective. To promote reliability, the PC is required to provide the results of the evaluation to each impacted Transmission Planner and Planning Coordinator, in addition to each reviewing RC and RAS-entity. In cases where a RAS crosses PC boundaries, each affected PC is responsible for conducting either individual evaluations or participating in a coordinated evaluation.

The previous version of this standard (PRC-012-1 Requirement 1, R1.4) states "… the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the Contingency for which it was designed, and not exceed TPL-003-0." Requirement R4 clarifies that the inadvertent operation to be considered would only be that caused by the malfunction of a single RAS component. This allows security features to be designed into the RAS such that inadvertent operation due to a single component malfunction is prevented. Otherwise, consistent with PRC-012-1 Requirement 1, R1.4, the RAS should be designed so that its whole or partial inadvertent operation due to a single component malfunction satisfies the System performance requirements for the same Contingency for which the RAS was designed.

If the RAS was installed for an extreme event in TPL-001-4 or for some other Contingency or System condition not defined in TPL-001-4 (therefore without performance requirements), its inadvertent operation still must meet some minimum System performance requirements. However, instead of referring to the TPL-001-4, Requirement R4 lists the System performance requirements that the inadvertent operation must satisfy. The performance requirements listed (Parts 4.1.4.1 – 4.1.4.5) are the ones that are common to all planning events P0-P7 listed in TPL-001-4.

Rationale for Requirement R5: The correct operation of a RAS is important for maintaining the reliability and integrity of the BES. Any incorrect operation of a RAS indicates that the RAS effectiveness and/or coordination has been compromised. Therefore, all operations of a RAS and failures of a RAS to operate when expected must be analyzed to verify that the RAS operation was consistent with its intended functionality and design.

A RAS operational performance analysis is intended to: 1) verify RAS operation was consistent with the implemented design; or 2) identify RAS performance deficiencies that manifested in the incorrect RAS operation or failure of RAS to operate when expected.

The 120 full calendar day time frame for the completion of RAS operational performance analysis aligns with the time frame established in Requirement R1 from PRC-004-4 regarding the investigation of a Protection System Misoperation. To promote reliability, each RAS-entity is required to provide the results of RAS operational performance analyses that identified any deficiencies to its reviewing RC(s).

RAS-entities may need to collaborate with their associated Transmission Planner to comprehensively analyze RAS operational performance. This is because a RAS operational performance analysis involves verifying that the RAS operation was triggered correctly (Part 5.1.1), responded as designed (Part 5.1.2), and that the resulting BES response (Parts 5.1.3 and 5.1.4) was consistent with the intended functionality and design of the RAS. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to conduct and submit a single, coordinated operational performance analysis.

Rationale for Requirement R6: Deficiencies identified in the periodic RAS evaluation conducted by the PC pursuant to Requirement R4, in the operational performance analysis conducted by the RAS-entity pursuant to Requirement R5, or in the functional test performed by the RAS-entity pursuant to Requirement R8, potentially pose a reliability risk to the BES. To mitigate these potential reliability risks, Requirement R6 mandates that each RAS-entity develop a Corrective Action Plan (CAP) to address the identified deficiency. The CAP contains the mitigation actions and associated timetable necessary to remedy the specific deficiency. The RAS-entity may request assistance with CAP development from other parties such as its Transmission Planner or Planning Coordinator; however, the RAS-entity has the responsibility for compliance with this requirement.

If the CAP requires that a functional change be made to a RAS, the RAS-entity will need to submit information identified in Attachment 1 to the reviewing RC(s) prior to placing RAS modifications in service per Requirement R1.

Depending on the complexity of the identified deficiency(ies), development of a CAP may require studies, and other engineering or consulting work. A maximum time frame of six full calendar months is specified for RAS-entity collaboration on the CAP development. Ideally, when there is more than one RAS-entity for a RAS, the RAS-entities would collaborate to develop and submit a single, coordinated CAP.

Rationale for Requirement R7: Requirement R7 mandates each RAS-entity implement a CAP (developed in Requirement R6) that mitigates the deficiencies identified in Requirements R4, R5, or R8. By definition, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem." The implementation of a properly developed CAP ensures that RAS deficiencies are mitigated in a timely manner. Each reviewing Reliability Coordinator must be notified if CAP actions or timetables change, and when the CAP is completed.

Rationale for Requirement R8: Due to the wide variety of RAS designs and implementations, and the potential for impacting BES reliability, it is important that periodic functional testing of a RAS be performed. A functional test provides an overall confirmation of the RAS to operate as designed and verifies the proper operation of the non-Protection System (control) components of a RAS that are not addressed in PRC-005. Protection System components that are part of a RAS are maintained in accordance with PRC-005.

The six or twelve full calendar year test interval, which begins on the effective date of the standard pursuant to the PRC-012-2 implementation plan, is a balance between the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Extending to longer intervals increases the reliability risk to the BES posed by an undiscovered latent failure that could cause an incorrect operation or failure of the RAS. The RAS-entity is in the best position to determine the testing procedure and schedule due to its overall knowledge of the RAS design, installation, and functionality. Functional testing may be accomplished with end-to-end testing or a segmented approach. For segmented testing, each segment of a RAS must be tested. Overlapping segments can be tested individually negating the need for complex maintenance schedules and outages.

The maximum allowable interval between functional tests is six full calendar years for RAS that are not designated as limited impact RAS and twelve full calendar years for RAS that are designated as limited impact RAS. The interval between tests begins on the date of the most recent successful test for each individual segment or end-to-end test. A successful test of one segment only resets the test interval clock for that segment. A correct operation of a RAS qualifies as a functional test for those RAS segments which operate (documentation for compliance with Requirement R5 Part 5.1). If an event causes a partial operation of a RAS, the segments without an operation will require a separate functional test within the maximum interval with the starting date determined by the previous successful test of the segments that did not operate.

Rationale for Requirement R9: The RAS database is a comprehensive record of all RAS existing in a Reliability Coordinator Area. The database enables the RC to provide other entities high-level information on existing RAS that could potentially impact the operational and/or planning activities of that entity. Attachment 3 lists the minimum information required for the RAS database, which includes a summary of the RAS initiating conditions, corrective actions, and System issues being mitigated. This information allows an entity to evaluate the reliability need for requesting more detailed information from the RAS-entities identified in the database contact information. The RC is the appropriate entity to maintain the database because the RC receives the required database information when a new or modified RAS is submitted for review. The twelve full calendar month time frame is aligned with industry practice and allows sufficient time for the RC to collect the appropriate information from RAS-entities and update the RAS database.

British Columbia Utilities Commission (BCUC)
Implementation Plan for PRC-012-2 – Remedial Action Schemes (RAS)

Requested Approval

- PRC-012-2 – Remedial Action Schemes

Requested Retirements

- PRC-015-1 – Remedial Action Scheme Data and Documentation
- PRC-016-1 – Remedial Action Scheme Misoperations

Applicable Entities

- Reliability Coordinator
- RAS-entity – the Transmission Owner, Generator Owner or Distribution Provider that owns all or part of a RAS

General Considerations

Reliability Standard PRC-012-2 consolidates previously unapproved standards and revises other RAS-related standards. Reliability Standard PRC-012-2 also provides clear and unambiguous responsibilities to the specific users, owners and operators of the Bulk Electric System. Reliability Standard PRC-012-2 establishes a new working framework between RAS-entities, Planning Coordinators (PCs), and Reliability Coordinators (RCs), and this new framework will involve considerable start-up effort. As such, implementation of Reliability Standard PRC-012-2 will occur over a 36-month period after approval of the standard by the BCUC.

Limited Impact RAS

A RAS implemented prior to the effective date of PRC-012-2 that has been through the regional review process of the Western Electricity Coordinating Council (WECC) and is classified as a Local Area Protection Scheme (LAPS) in WECC is recognized as a limited impact RAS upon the effective date of PRC-012-2 and is subject to all applicable requirements.

Effective Date

Reliability Standard PRC-012-2 shall become effective on October 1, 2021 after the BCUC's order approving the standard. Provisions concerning the initial performance of obligations under Requirements R1, R2, R4, R8 and R9 are outlined below.

Requirements R1, R2 and R4

Attachment 1, Section II Parts 6d) and 6e) as referenced from Requirement R1, Attachment 2 Section I Parts 7d) and 7e) as referenced from Requirement R2, and all of Requirement R4 are held in abeyance in British Columbia pending resolution of the Planning Authority/Planning Coordination role and responsibility process as managed by the BCUC. Pending the aforementioned process, these requirements shall be formally re-assessed in British Columbia to determine the effective date of the aforementioned attachment sections.

Requirement R8

For each RAS not designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within six full calendar years after the effective date for PRC-012-2, as described above.

For each RAS designated as limited impact, initial performance of obligations under Requirement R8 must be completed at least once within twelve full calendar years after the effective date for PRC-012-2, as described above.

Requirement R9

For each Reliability Coordinator that does not have a RAS database, the initial obligation under Requirement R9 is to establish a database by the effective date of PRC-012-2.

Each Reliability Coordinator will perform the obligation of Requirement R9 within twelve full calendar months after the effective date of PRC-012-2, as described above.

Retirement of Existing Standards

The Reliability Standards for retirement shall be retired immediately prior to the effective date of PRC-012-2.

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-2

3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. **Applicability**

   4.1. Functional Entity

   4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinators

   4.2. Circuits

   4.2.1 Circuits Subject to Requirements R1 – R5

   4.2.1.1 Transmission lines operated at 200 kV and above.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

   4.2.2 Circuits Subject to Requirement R6

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

   4.2.2.2 Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. **Effective Dates***

The effective dates of the requirements in the PRC-023-2 standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

*** Mandatory BC Effective Date: Requirement Dependent**

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption
	• For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability	First day of the first calendar quarter 12 months after applicable regulatory approvals	First day of the first calendar quarter 12 months after Board of Trustees adoption
	• For supervisory elements as described in PRC-023-2 - Attachment A, Section 1.6	First day of the first calendar quarter 24 months after applicable regulatory approvals	First day of the first calendar quarter 24 months after Board of Trustees adoption
	• For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3	Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011[1]
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on

1 July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Standard PRC-023-2 — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5	First day of the first calendar quarter 18 months after applicable regulatory approvals	First day of the first calendar quarter 18 months after Board of Trustees adoption

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
   - 115% of the highest emergency rating of the series capacitor.
   - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating

10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[3].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[4].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

[3] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4

[4] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-2 per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Authority

The British Columbia Utilities Commission

1.2. Data Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

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

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit. OR

Standard PRC-023-2 — Transmission Relay Loadability

Requirement	Lower	Moderate	High	Severe
				The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments.	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments.	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within

Requirement	Lower	Moderate	High	Severe
		OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission

Requirement	Lower	Moderate	High	Severe
				Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

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Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	

PRC-023 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
    - **1.1.** Phase distance.
    - **1.2.** Out-of-step tripping.
    - **1.3.** Switch-on-to-fault.
    - **1.4.** Overcurrent relays.
    - **1.5.** Communications aided protection schemes including but not limited to:
        - **1.5.1** Permissive overreach transfer trip (POTT).
        - **1.5.2** Permissive under-reach transfer trip (PUTT).
        - **1.5.3** Directional comparison blocking (DCB).
        - **1.5.4** Directional comparison unblocking (DCUB).
    - **1.6.** Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
    - **2.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
        - Overcurrent elements that are only enabled during loss of potential conditions.
        - Elements that are only enabled during a loss of communications except as noted in section 1.6
    - **2.2.** Protection systems intended for the detection of ground fault conditions.
    - **2.3.** Protection systems intended for protection during stable power swings.
    - **2.4.** Generator protection relays that are susceptible to load.
    - **2.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
    - **2.6.** Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
    - **2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
    - **2.8.** Relay elements associated with dc lines.
    - **2.9.** Relay elements associated with dc converter transformers.

PRC-023 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[5] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[5] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-4
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**

   4.1. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-4 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates*:** See Implementation Plan for the Revised Definition of "Remedial Action Scheme".

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
    - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
    - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
    - 115% of the highest emergency rating of the series capacitor.
    - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

[1] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-4 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-4, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-4, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The British Columbia Utilities Commission

1.2. Data Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

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

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

   "Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Version	Date	Action	Change Tracking
4	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
4	November 19, 2015	FERC Order issued approving PRC-023-4. Docket No. RM15-13-000.	

PRC-023-4 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

2. The following protection systems are excluded from requirements of this standard:

2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

- Overcurrent elements that are only enabled during loss of potential conditions.
- Elements that are only enabled during a loss of communications except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-4 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**
2. **Number:** **PRC-026-1**
3. **Purpose:** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1** Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.
     - **4.1.2** Planning Coordinator.
     - **4.1.3** Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.
   - **4.2. Facilities:** The following Elements that are part of the Bulk Electric System (BES):
     - **4.2.1** Generators.
     - **4.2.2** Transformers.
     - **4.2.3** Transmission lines.
5. **Background:**

This is the third phase of a three-phased standard development project that focused on developing this new Reliability Standard to address protective relay operations due to stable power swings. The March 18, 2010, Federal Energy Regulatory Commission (FERC) Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In that Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

Phase 1 focused on making the specific modifications from FERC Order No. 733 to PRC-023-1. Reliability Standard PRC-023-2, which incorporated these modifications, became mandatory on July 1, 2012.

Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. PRC-025-1 became mandatory on October 1, 2014, along with PRC-023-3, which was modified to harmonize PRC-023-2 with PRC-025-1.

Phase 3 focuses on preventing protective relays from tripping unnecessarily due to stable power swings by requiring identification of Elements on which a stable or unstable power swing may affect Protection System operation, assessment of the security of load-responsive protective relays to tripping in response to only a stable power swing, and implementation of Corrective Action Plans (CAP), where necessary. Phase 3 improves security of load-responsive protective relays for stable power swings so they are expected to not trip in response to stable power swings during non-Fault conditions while maintaining dependable fault detection and dependable out-of-step tripping.

6. **~~Effective Dates:~~**

~~Requirement R1~~

~~First day of the first full calendar year that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Requirements R2, R3, and R4~~

~~First day of the first full calendar year that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first full calendar year that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s).
2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint.
3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[2] power swing during a simulated disturbance.

M1. Each Planning Coordinator shall have dated evidence that demonstrates notification of the generator, transformer, and transmission line BES Element(s) that meet one or more of the criteria in Requirement R1, if any, to the respective Generator Owner and Transmission Owner. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.

[2] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

R2. Each Generator Owner and Transmission Owner shall: [Violation Risk Factor: High] [Time Horizon: Operations Planning]

2.1 Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-1 – Attachment B criteria has not been performed in the last five calendar years.

2.2 Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B.

M2. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates the evaluation was performed according to Requirement R2. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

R3. Each Generator Owner and Transmission Owner shall, within six full calendar months of determining a load-responsive protective relay does not meet the PRC-026-1 – Attachment B criteria pursuant to Requirement R2, develop a Corrective Action Plan (CAP) to meet one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- The Protection System meets the PRC-026-1 – Attachment B criteria, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element); or
- The Protection System is excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element).

M3. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement R3. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

R4. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R3 and update each CAP if actions or timetables change until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M4. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R4, including updates to the CAP when actions or timetables change. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1. Compliance Enforcement Authority~~

~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~

~~1.2. Evidence Retention~~

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

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

- ~~The Planning Coordinator shall retain evidence of Requirement R1 for a minimum of one calendar year following the completion of the Requirement.~~
- ~~The Generator Owner and Transmission Owner shall retain evidence of Requirement R2 evaluation for a minimum of 12 calendar months following completion of each evaluation where a CAP is not developed.~~
- ~~The Generator Owner and Transmission Owner shall retain evidence of Requirements R2, R3, and R4 for a minimum of 12 calendar months following completion of each CAP.~~

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

[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing."

[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, "Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis."

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

~~1.3. Compliance Monitoring and Assessment Processes:~~

~~As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~

~~1.4. Additional Compliance Information~~

~~None.~~

Table of Compliance Elements

~~R#~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**R1**~~	~~Long-term Planning~~	~~Medium~~	~~The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was less than or equal to 30 calendar days late.~~	~~The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.~~	~~The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.~~	~~The Planning Coordinator provided notification of the BES Element(s) in accordance with Requirement R1, but was more than 90 calendar days late.~~ ~~OR~~ ~~The Planning Coordinator failed to provide notification of the BES Element(s) in accordance with Requirement R1.~~

~~R#~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**R2**~~	~~Operations Planning~~	~~High~~	~~The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was less than or equal to 30 calendar days late.~~	~~The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.~~	~~The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.~~	~~The Generator Owner or Transmission Owner evaluated its load-responsive protective relay(s) in accordance with Requirement R2, but was more than 90 calendar days late.~~ ~~OR~~ ~~The Generator Owner or Transmission Owner failed to evaluate its load-responsive protective relay(s) in accordance with Requirement R2.~~

~~R#~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**R3**~~	~~Long-term Planning~~	~~Medium~~	~~The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than six calendar months and less than or equal to seven calendar months.~~	~~The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than seven calendar months and less than or equal to eight calendar months.~~	~~The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than eight calendar months and less than or equal to nine calendar months.~~	~~The Generator Owner or Transmission Owner developed a Corrective Action Plan (CAP) in accordance with Requirement R3, but in more than nine calendar months.~~ ~~OR~~ ~~The Generator Owner or Transmission Owner failed to develop a CAP in accordance with Requirement R3.~~
~~**R4**~~	~~Long-term Planning~~	~~Medium~~	~~The Generator Owner or Transmission Owner implemented a Corrective Action Plan (CAP), but failed to update a CAP when actions or timetables changed, in accordance with Requirement R4.~~	~~N/A~~	~~N/A~~	~~The Generator Owner or Transmission Owner failed to implement a Corrective Action Plan (CAP) in accordance with Requirement R4.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Applied Protective Relaying, Westinghouse Electric Corporation, 1979.

Burdy, John, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

IEEE Power System Relaying Committee WG D6, *Power Swing and Out-of-Step Considerations on Transmission Lines*, July 2005: http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Kimbark Edward Wilson, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

Kundur, Prabha, *Power System Stability and Control*, 1994, Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald, *Protective Relaying for Power Generation Systems*, 2006, Boca Raton: CRC Press.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by NERC Board of Trustees	New
1	March 17, 2016	FERC Order issued approving PRC-026-1. Docket No. RM15-8-000.	

PRC-026-1 – Attachment A

This standard applies to any protective functions which could trip instantaneously or with a time delay of less than 15 cycles on load current (i.e., "load-responsive") including, but not limited to:

- Phase distance
- Phase overcurrent
- Out-of-step tripping
- Loss-of-field

The following protection functions are excluded from Requirements of this standard:

- Relay elements supervised by power swing blocking
- Relay elements that are only enabled when other relays or associated systems fail. For example:
    - Overcurrent elements that are only enabled during loss of potential conditions.
    - Relay elements that are only enabled during a loss of communications
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with direct current (dc) lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

PRC-026-1 – Attachment B

Criterion A:

An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region.[5] The unstable power swing region is formed by the union of three shapes in the impedance (R-X) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

[5] Guidelines and Technical Basis, Figures 1 and 2.

PRC-026-1 – Attachment B

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.
2. All generation is in service and all transmission BES Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.
4. Both the sending-end and receiving-end voltages at 1.05 per unit.

Guidelines and Technical Basis

Introduction

The NERC System Protection and Control Subcommittee technical document, *Protection System Response to Power Swings*, August 2013,[6] ("PSRPS Report" or "report") was specifically prepared to support the development of this NERC Reliability Standard. The report provided a historical perspective on power swings as early as 1965 up through the approval of the report by the NERC Planning Committee. The report also addresses reliability issues regarding trade-offs between security and dependability of Protection Systems, considerations for this NERC Reliability Standard, and a collection of technical information about power swing characteristics and varying issues with practical applications and approaches to power swings. Of these topics, the report suggests an approach for this NERC Reliability Standard ("standard" or "PRC-026-1") which is consistent with addressing three regulatory directives in the FERC Order No. 733. The first directive concerns the need for "…protective relay systems that differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement."[7] Second, is "…to develop a Reliability Standard addressing undesirable relay operation due to stable power swings."[8] The third directive "…to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings"[9] was considered during development of the standard.

The development of this standard implements the majority of the approaches suggested by the report. However, it is noted that the Reliability Coordinator and Transmission Planner have not been included in the standard's Applicability section (as suggested by the PSRPS Report). This is so that a single entity, the Planning Coordinator, may be the single source for identifying Elements according to Requirement R1. A single source will insure that multiple entities will not identify Elements in duplicate, nor will one entity fail to provide an Element because it believes the Element is being provided by another entity. The Planning Coordinator has, or has access to, the wide-area model and can correctly identify the Elements that may be susceptible to a stable or unstable power swing. Additionally, not including the Reliability Coordinator and Transmission Planner is consistent with the applicability of other relay loadability NERC Reliability Standards (e.g., PRC-023 and PRC-025). It is also consistent with the NERC Functional Model.

The phrase, "while maintaining dependable fault detection and dependable out-of-step tripping" in Requirement R3, describes that the Generator Owner and Transmission Owner are to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the transmission system, and

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[6] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

[7] Transmission Relay Loadability Reliability Standard, Order No. 733, P.150 FERC ¶ 61,221 (2010).

[8] Ibid. P.153.

[9] Ibid. P.162.

this standard is not intended to result in the loss of these protection functions. Instead, the Generator Owner and Transmission Owner must consider both the Requirements within this standard and its desired protection goals and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

Power Swings

The IEEE Power System Relaying Committee WG D6 developed a technical document called *Power Swing and Out-of-Step Considerations on Transmission Lines* (July 2005) that provides background on power swings. The following are general definitions from that document:[10]

> Power Swing: a variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
>
> Pole Slip: a condition whereby a generator, or group of generators, terminal voltage angles (or phases) go past 180 degrees with respect to the rest of the connected power system.
>
> Stable Power Swing: a power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
>
> Unstable Power Swing: a power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.
>
> Out-of-Step Condition: Same as an unstable power swing.
>
> Electrical System Center or Voltage Zero: it is the point or points in the system where the voltage becomes zero during an unstable power swing.

Burden to Entities

The PSRPS Report provides a technical basis and approach for focusing on Protection Systems, which are susceptible to power swings, while achieving the purpose of the standard. The approach reduces the number of relays to which the PRC-026-1 Requirements would apply by first identifying the BES Element(s) on which load-responsive protective relays must be evaluated. The first step uses criteria to identify the Elements on which a Protection System is expected to be challenged by power swings. Of those Elements, the second step is to evaluate each load-responsive protective relay that is applied on each identified Element. Rather than requiring the Planning Coordinator or Transmission Planner to perform simulations to obtain information for each identified Element, the Generator Owner and Transmission Owner will reduce the need for simulation by comparing the load-responsive protective relay characteristic to specific criteria in PRC-026-1 – Attachment B.

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[10] http://www.pes-psrc.org/Reports/Power%20Swing%20and%20OOS%20Considerations%20on%20Transmission%20Lines%20F..pdf.

Applicability

The standard is applicable to the Generator Owner, Planning Coordinator, and Transmission Owner entities. More specifically, the Generator Owner and Transmission Owner entities are applicable when applying load-responsive protective relays at the terminals of the applicable BES Elements. The standard is applicable to the following BES Elements: generators, transformers, and transmission lines. The Distribution Provider was considered for inclusion in the standard; however, it is not subject to the standard because this entity, by functional registration, would not own generators, transmission lines, or transformers other than load serving.

Load-responsive protective relays include any protective functions which could trip with or without time delay, on load current.

Requirement R1

The Planning Coordinator has a wide-area view and is in the position to identify what, if any, Elements meet the criteria. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document, *Protection System Response to Power Swings (*August 2013),[11] which recommends a focused approach to determine an at-risk Element. Identification of Elements comes from the annual Planning Assessments pursuant to the transmission planning (i.e., "TPL") and other NERC Reliability Standards (e.g., PRC-006), and the standard is not requiring any other assessments to be performed by the Planning Coordinator. The required notification on a calendar year basis to the respective Generator Owner and Transmission Owner is sufficient because it is expected that the Planning Coordinator will make its notifications following the completion of its annual Planning Assessments. The Planning Coordinator will continue to provide notification of Elements on a calendar year basis even if a study is performed less frequently (e.g., PRC-006 – Automatic Underfrequency Load Shedding, which is five years) and has not changed. It is possible that a Planning Coordinator could utilize studies from a prior year in determining the necessary notifications pursuant to Requirement R1.

Criterion 1

The first criterion involves generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). For example, a scheme to remove generation for specific conditions is implemented for a four-unit generating plant (1,100 MW). Two of the units are 500 MW each; one is connected to the 345 kV system and one is connected to the 230 kV system. The Transmission Owner has two 230 kV transmission lines and one 345 kV transmission line all terminating at the generating facility as well as a 345/230 kV autotransformer. The remaining 100 MW consists of two 50 MW combustion turbine (CT) units connected to four 66 kV transmission lines. The 66 kV transmission lines are not electrically joined to the 345 kV and 230 kV transmission lines at the plant site and are not subject to the operating limit or RAS. A stability constraint limits the output of the portion of the plant affected

[11] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20 20/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

by the RAS to 700 MW for an outage of the 345 kV transmission line. The RAS trips one of the 500 MW units to maintain stability for a loss of the 345 kV transmission line when the total output from both 500 MW units is above 700 MW. For this example, both 500 MW generating units and the associated generator step-up (GSU) transformers would be identified as Elements meeting this criterion. The 345/230 kV autotransformer, the 345 kV transmission line, and the two 230 kV transmission lines would also be identified as Elements meeting this criterion. The 50 MW combustion turbines and 66 kV transmission lines would not be identified pursuant to Criterion 1 because these Elements are not subject to an operating limit or RAS and do not terminate at the Transmission station associated with the generators that are subject to the SOL or RAS.

Criterion 2

The second criterion involves Elements that are monitored as a part of an established System Operating Limit (SOL) based on an angular stability limit regardless of the outage conditions that result in the enforcement of the SOL. For example, if two long parallel 500 kV transmission lines have a combined SOL of 1,200 MW, and this limit is based on angular instability resulting from a fault and subsequent loss of one of the two lines, then both lines would be identified as Elements meeting the criterion.

Criterion 3

The third criterion involves Elements that form the boundary of an island within an underfrequency load shedding (UFLS) design assessment. The criterion applies to islands identified based on application of the Planning Coordinator's criteria for identifying islands, where the island is formed by tripping the Elements based on angular instability. The criterion applies if the angular instability is modeled in the UFLS design assessment, or if the boundary is identified "off-line" (i.e., the Elements are selected based on angular instability considerations, but the Elements are tripped in the UFLS design assessment without modeling the initiating angular instability). In cases where an out-of-step condition is detected and tripping is initiated at an alternate location, the criterion applies to the Element on which the power swing is detected. The criterion does not apply to islands identified based on other considerations that do not involve angular instability, such as excessive loading, Planning Coordinator area boundary tie lines, or Balancing Authority boundary tie lines.

Criterion 4

The fourth criterion involves Elements identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable[12] power swing during a simulated disturbance. The intent is for the Planning Coordinator to include any Element(s) where relay tripping was observed during simulations performed for the most recent annual Planning Assessment associated with the transmission planning TPL-001-4 Reliability Standard. Note that relay tripping must be assessed within those annual Planning Assessments per TPL-001-4, R4,

[12] Refer to the "Justification for Including Unstable Power Swings in the Requirements" section.

Part 4.3.1.3, which indicates that analysis shall include the “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.” Identifying such Elements according to Criterion 4 and notifying the respective Generator Owner and Transmission Owner will require that the owners of any load-responsive protective relay applied at the terminals of the identified Element evaluate the relay’s susceptibility to tripping in response to a stable power swing.

Planning Coordinators have the discretion to determine whether the observed tripping for a power swing in its Planning Assessments occurs for valid contingencies and system conditions. The Planning Coordinator will address tripping that is observed in transient analyses on an individual basis; therefore, the Planning Coordinator is responsible for identifying the Elements based only on simulation results that are determined to be valid.

Due to the nature of how a Planning Assessment is performed, there may be cases where a previously-identified Element is not identified in the most recent annual Planning Assessment. If so, this is acceptable because the Generator Owner and Transmission Owner would have taken action upon the initial notification of the previously identified Element. When an Element is not identified in later Planning Assessments, the risk of load-responsive protective relays tripping in response to a stable power swing during non-Fault conditions would have already been assessed under Requirement R2 and mitigated according to Requirements R3 and R4 where the relays did not meet the PRC-026-1 – Attachment B criteria. According to Requirement R2, the Generator Owner and Transmission Owner are only required to re-evaluate each load-responsive protective relay for an identified Element where the evaluation has not been performed in the last five calendar years.

Although Requirement R1 requires the Planning Coordinator to notify the respective Generator Owner and Transmission Owner of any Elements meeting one or more of the four criteria, it does not preclude the Planning Coordinator from providing additional information, such as apparent impedance characteristics, in advance or upon request, that may be useful in evaluating protective relays. Generator Owners and Transmission Owners are able to complete protective relay evaluations and perform the required actions without additional information. The standard does not include any requirement for the entities to provide information that is already being shared or exchanged between entities for operating needs. While a Requirement has not been included for the exchange of information, entities should recognize that relay performance needs to be measured against the most current information.

Requirement R2

Requirement R2 requires the Generator Owner and Transmission Owner to evaluate its load-responsive protective relays to ensure that they are expected to not trip in response to stable power swings.

The PRC-026-1 – Attachment A lists the applicable load-responsive relays that must be evaluated which include phase distance, phase overcurrent, out-of-step tripping, and loss-of-field relay functions. Phase distance relays could include, but are not limited to, the following:

- Zone elements with instantaneous tripping or intentional time delays of less than 15 cycles
- Phase distance elements used in high-speed communication-aided tripping schemes including:
  - Directional Comparison Blocking (DCB) schemes
  - Directional Comparison Un-Blocking (DCUB) schemes
  - Permissive Overreach Transfer Trip (POTT) schemes
  - Permissive Underreach Transfer Trip (PUTT) schemes

A method is provided within the standard to support consistent evaluation by Generator Owners and Transmission Owners based on specified conditions. Once a Generator Owner or Transmission Owner is notified of Elements pursuant to Requirement R1, it has 12 full calendar months to determine if each Element's load-responsive protective relays meet the PRC-026-1 – Attachment B criteria, if the determination has not been performed in the last five calendar years. Additionally, each Generator Owner and Transmission Owner, that becomes aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relays pursuant to Requirement R2, Part 2.2, must perform the same PRC-026-1 – Attachment B criteria determination within 12 full calendar months.

Becoming Aware of an Element That Tripped in Response to a Power Swing

Part 2.2 in Requirement R2 is intended to initiate action by the Generator Owner and Transmission Owner when there is a known stable or unstable power swing and it resulted in the entity's Element tripping. The criterion starts with becoming aware of the event (i.e., power swing) and then any connection with the entity's Element tripping. By doing so, the focus is removed from the entity having to demonstrate that it made a determination whether a power swing was present for every Element trip. The basis for structuring the criterion in this manner is driven by the available ways that a Generator Owner and Transmission Owner could become aware of an Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s).

Element trips caused by stable or unstable power swings, though infrequent, would be more common in a larger event. The identification of power swings will be revealed during an analysis of the event. Event analysis where an entity may become aware of a stable or unstable power swing could include internal analysis conducted by the entity, the entity's Protection System review following a trip, or a larger scale analysis by other entities. Event analysis could include involvement by the entity's Regional Entity, and in some cases NERC.

Information Common to Both Generation and Transmission Elements

The PRC-026-1 – Attachment A lists the load-responsive protective relays that are subject to this standard. Generator Owners and Transmission Owners may own load-responsive protective relays (e.g., distance relays) that directly affect generation or transmission BES Elements and will require analysis as a result of Elements being identified by the Planning Coordinator in Requirement R1 or the Generator Owner or Transmission Owner in Requirement R2. For example, distance relays owned by the Transmission Owner may be installed at the high-voltage side of the generator step-up (GSU) transformer (directional toward the generator) providing backup to generation protection. Generator Owners may have distance relays applied to backup transmission protection or backup protection to the GSU transformer. The Generator Owner may have relays installed at the generator terminals or the high-voltage side of the GSU transformer.

Exclusion of Time Based Load-Responsive Protective Relays

The purpose of the standard is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions." Load-responsive, high-speed tripping protective relays pose the highest risk of operating during a power swing. Because of this, high-speed tripping protective relays and relays with a time delay of less than 15 cycles are included in the standard; whereas other relays (i.e., Zones 2 and 3) with a time delay of 15 cycles or greater are excluded. The time delay used for exclusion on some load-responsive protective relays is based on the maximum expected time that load-responsive protective relays would be exposed to a stable power swing with a slow slip rate frequency.

In order to establish a time delay that distinguishes a high-risk load-responsive protective relay from one that has a time delay for tripping (lower-risk), a sample of swing rates were calculated based on a stable power swing entering and leaving the impedance characteristic as shown in Table 1. For a relay impedance characteristic that has a power swing entering and leaving, beginning at 90 degrees with a termination at 120 degrees before exiting the zone, the zone timer must be greater than the calculated time the stable power swing is inside the relay's operating zone to not trip in response to the stable power swing.

Eq. (1) $$Zone\ timer > 2 \times \left(\frac{(120° - Angle\ of\ entry\ into\ the\ relay\ characteristic) \times 60}{(360 \times Slip\ Rate)}\right)$$

Table 1: Swing Rates	
Zone Timer (Cycles)	**Slip Rate (Hz)**
10	1.00
15	0.67
20	0.50
30	0.33

With a minimum zone timer of 15 cycles, the corresponding slip rate of the system is 0.67 Hz. This represents an approximation of a slow slip rate during a system Disturbance. Longer time delays allow for slower slip rates.

Application to Transmission Elements

Criterion A in PRC-026-1 – Attachment B describes an unstable power swing region that is formed by the union of three shapes in the impedance (R-X) plane. The first shape is a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7 (i.e., E_S / E_R = 0.7 / 1.0 = 0.7). The second shape is an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43 (i.e., E_S / E_R = 1.0 / 0.7 = 1.43). The third shape is a lens that connects the endpoints of the total system impedance together by varying the sending-end and receiving-end system voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance (with the parallel transfer impedance removed—see Figures 1 through 5). The total system impedance is derived from a two-bus equivalent network and is determined by summing the sending-end source impedance, the line impedance (excluding the Thévenin equivalent transfer impedance), and the receiving-end source impedance as shown in Figures 6 and 7. Establishing the total system impedance provides a conservative condition that will maximize the security of the relay against various system conditions. The smallest total system impedance represents a condition where the size of the lens characteristic in the R-X plane is smallest and is a conservative operating point from the standpoint of ensuring a load-responsive protective relay is expected to not trip given a predetermined angular displacement between the sending-end and receiving-end voltages. The smallest total system impedance results when all generation is in service and all transmission BES Elements are modeled in their "normal" system configuration (PRC-026-1 – Attachment B, Criterion A). The parallel transfer impedance is removed to represent a likely condition where parallel Elements may be lost during the disturbance, and the loss of these Elements magnifies the sensitivity of the load-responsive relays on the parallel line by removing the "infeed effect" (i.e., the apparent impedance sensed by the relay is decreased as a result of the loss of the transfer impedance, thus making the relay more likely to trip for a stable power swing—See Figures 13 and 14).

The sending-end and receiving-end source voltages are varied from 0.7 to 1.0 per unit to form the lower and upper loss-of-synchronism circles. The ratio of these two voltages is used in the calculation of the loss-of-synchronism circles, and result in a ratio range from 0.7 to 1.43.

Eq. (2) $$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

Eq. (3): $$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

The internal generator voltage during severe power swings or transmission system fault conditions will be greater than zero due to voltage regulator support. The voltage ratio of 0.7 to 1.43 is chosen to be more conservative than the PRC-023[13] and PRC-025[14] NERC Reliability Standards where a lower bound voltage of 0.85 per unit voltage is used. A ±15% internal generator voltage range was chosen as a conservative voltage range for calculation of the voltage ratio used to calculate the loss-of-synchronism circles. For example, the voltage ratio using these voltages would result in a ratio range from 0.739 to 1.353.

[13] Transmission Relay Loadability

[14] Generator Relay Loadability

Eq. (4) $\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$ Eq. (5): $\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$

The lower ratio is rounded down to 0.7 to be more conservative, allowing a voltage range of 0.7 to 1.0 per unit to be used for the calculation of the loss-of-synchronism circles.[15]

When the parallel transfer impedance is included in the model, the division of current through the parallel transfer impedance path results in actual measured relay impedances that are larger than those measured when the parallel transfer impedance is removed (i.e., infeed effect), which would make it more likely for an impedance relay element to be completely contained within the unstable power swing region as shown in Figure 11. If the transfer impedance is included in the evaluation, a distance relay element could be deemed as meeting PRC-026-1 – Attachment B criteria and, in fact would be secure, assuming all Elements were in their normal state. In this case, the distance relay element could trip in response to a stable power swing during an actual event if the system was weakened (i.e., a higher transfer impedance) by the loss of a subset of lines that make up the parallel transfer impedance as shown in Figure 10. This could happen because the subset of lines that make up the parallel transfer impedance tripped on unstable swings, contained the initiating fault, and/or were lost due to operation of breaker failure or remote back-up protection schemes.

Table 10 shows the percent size increase of the lens shape as seen by the relay under evaluation when the parallel transfer impedance is included. The parallel transfer impedance has minimal effect on the apparent size of the lens shape as long as the parallel transfer impedance is at least 10 multiples of the parallel line impedance (less than 5% lens shape expansion), therefore, its removal has minimal impact, but results in a slightly more conservative, smaller lens shape. Parallel transfer impedances of 5 multiples of the parallel line impedance or less result in an apparent lens shape size of 10% or greater as seen by the relay. If two parallel lines and a parallel transfer impedance tie the sending-end and receiving-end buses together, the total parallel transfer impedance will be one or less multiples of the parallel line impedance, resulting in an apparent lens shape size of 45% or greater. It is a realistic contingency that the parallel line could be out-of-service, leaving the parallel transfer impedance making up the rest of the system in parallel with the line impedance. Since it is not known exactly which lines making up the parallel transfer impedance will be out of service during a major system disturbance, it is most conservative to assume that all of them are out, leaving just the line under evaluation in service.

Either the saturated transient or sub-transient direct axis reactance may be used for machines in the evaluation because they are smaller than the un-saturated reactances. Since saturated sub-transient generator reactances are smaller than the transient or synchronous reactances, the use of sub-transient reactances will result in a smaller source impedance and a smaller unstable power swing region in the graphical analysis as shown in Figures 8 and 9. Because power swings occur in a time frame where generator transient reactances will be prevalent, it is acceptable to use saturated transient reactances instead of saturated sub-transient reactances. Because some short-

[15] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004, Section 6 (The Cascade Stage of the Blackout), p. 94 under "Why the Generators Tripped Off," states, "Some generator undervoltage relays were set to trip at or above 90% voltage. However, a motor stalls out at about 70% voltage and a motor starter contactor drops out around 75%, so if there is a compelling need to protect the turbine from the system the under-voltage trigger point should be no higher than 80%."

circuit models may not include transient reactances, the use of sub-transient reactances is also acceptable because it produces more conservative results. For this reason, either value is acceptable when determining the system source impedances (PRC-026-1 – Attachment B, Criterion A and B, No. 3).

Saturated reactances are used in short-circuit programs that produce the system impedance mentioned above. Planning and stability software generally use un-saturated reactances. Generator models used in transient stability analyses recognize that the extent of the saturation effect depends upon both rotor (field) and stator currents. Accordingly, they derive the effective saturated parameters of the machine at each instant by internal calculation from the specified (constant) unsaturated values of machine reactances and the instantaneous internal flux level. The specific assumptions regarding which inductances are affected by saturation, and the relative effect of that saturation, are different for the various generator models used. Thus, unsaturated values of all machine reactances are used in setting up planning and stability software data, and the appropriate set of open-circuit magnetization curve data is provided for each machine.

Saturated reactance values are smaller than unsaturated reactance values and are used in short-circuit programs owned by the Generator and Transmission Owners. Because of this, saturated reactance values are to be used in the development of the system source impedances.

The source or system equivalent impedances can be obtained by a number of different methods using commercially available short-circuit calculation tools.[16] Most short-circuit tools have a network reduction feature that allows the user to select the local and remote terminal buses to retain. The first method reduces the system to one that contains two buses, an equivalent generator at each bus (representing the source impedances at the sending-end and receiving-end), and two parallel lines; one being the line impedance of the protected line with relays being analyzed, the other being the parallel transfer impedance representing all other combinations of lines that connect the two buses together as shown in Figure 6. Another conservative method is to open both ends of the line being evaluated, and apply a three-phase bolted fault at each bus to determine the Thévenin equivalent impedance at each bus. The source impedances are set equal to the Thévenin equivalent impedances and will be less than or equal to the actual source impedances calculated by the network reduction method. Either method can be used to develop the system source impedances at both ends.

The two bullets of PRC-026-1 – Attachment B, Criterion A, No. 1, identify the system separation angles used to identify the size of the power swing stability boundary for evaluating load-responsive protective relay impedance elements. The first bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates a system separation angle of at least 120 degrees that is held constant while varying the sending-end and receiving-end source voltages from 0.7 to 1.0 per unit, thus creating an unstable power swing region about the total system impedance in Figure 1. This unstable power swing region is compared to the tripping portion of the distance relay characteristic; that is, the portion that is not supervised by load encroachment, blinders, or some other form of supervision as shown in Figure 12 that restricts the distance element from tripping

[16] Demetrios A. Tziouvaras and Daqing Hou, Appendix in *Out-Of-Step Protection Fundamentals and Advancements,* April 17, 2014: https://www.selinc.com.

for heavy, balanced load conditions. If the tripping portion of the impedance characteristics are completely contained within the unstable power swing region, the relay impedance element meets Criterion A in PRC-026-1 – Attachment B. A system separation angle of 120 degrees was chosen for the evaluation because it is generally accepted in the industry that recovery for a swing beyond this angle is unlikely to occur.[17]

The second bullet of PRC-026-1 – Attachment B, Criterion A, No. 1 evaluates impedance relay elements at a system separation angle of less than 120 degrees, similar to the first bullet described above. An angle less than 120 degrees may be used if a documented stability analysis demonstrates that the power swing becomes unstable at a system separation angle of less than 120 degrees.

The exclusion of relay elements supervised by Power Swing Blocking (PSB) in PRC-026-1 – Attachment A allows the Generator Owner or Transmission Owner to exclude protective relay elements if they are blocked from tripping by PSB relays. A PSB relay applied and set according to industry accepted practices prevent supervised load-responsive protective relays from tripping in response to power swings. Further, PSB relays are set to allow dependable tripping of supervised elements. The criteria in PRC-026-1 – Attachment B specifically applies to unsupervised elements that could trip for stable power swings. Therefore, load-responsive protective relay elements supervised by PSB can be excluded from the Requirements of this standard.

[17] "The critical angle for maintaining stability will vary depending on the contingency and the system condition at the time the contingency occurs; however, the likelihood of recovering from a swing that exceeds 120 degrees is marginal and 120 degrees is generally accepted as an appropriate basis for setting out-of-step protection. Given the importance of separating unstable systems, defining 120 degrees as the critical angle is appropriate to achieve a proper balance between dependable tripping for unstable power swings and secure operation for stable power swings." NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf), p. 28.

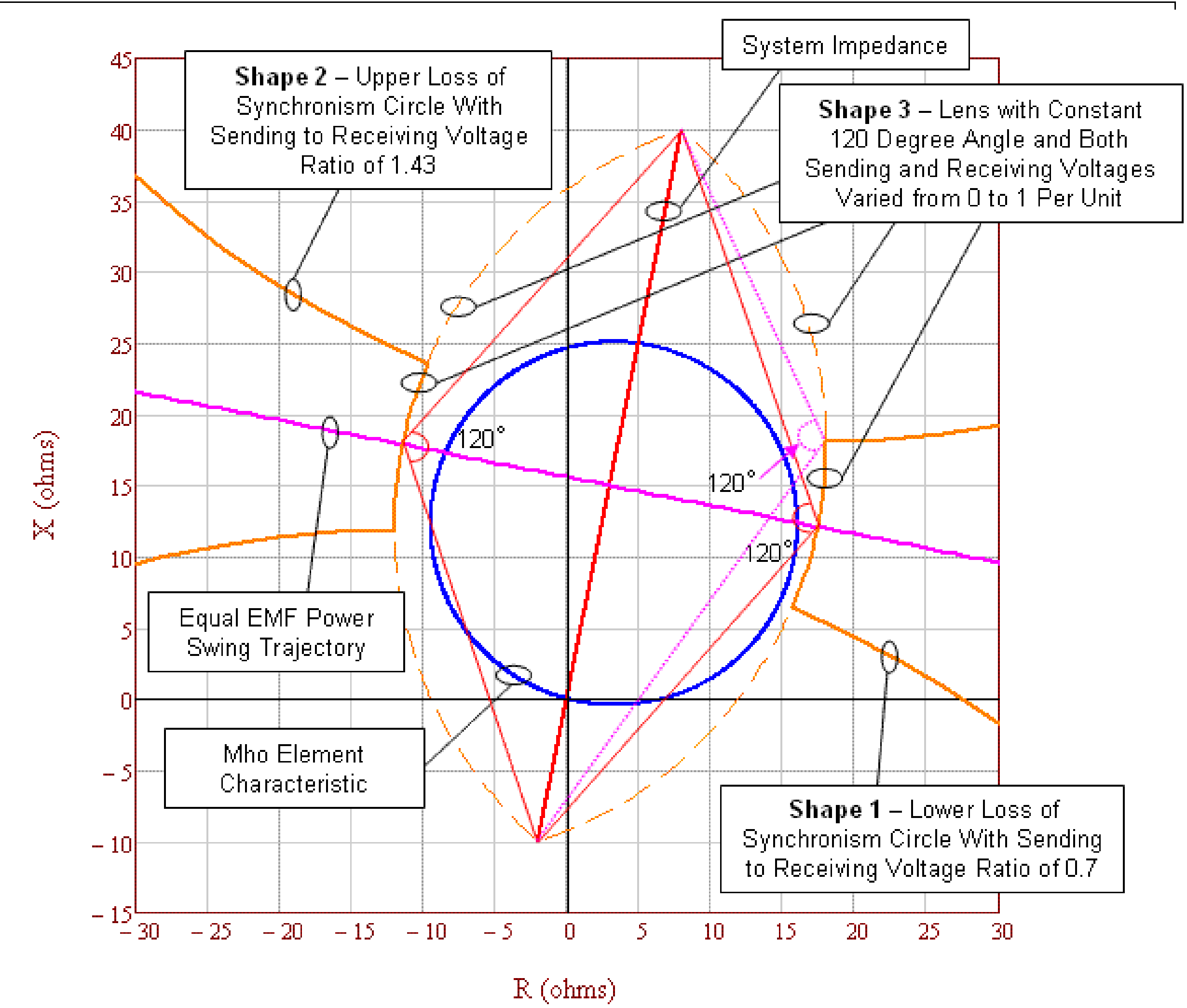


Figure 1: An enlarged graphic illustrating the unstable power swing region formed by the union of three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region (i.e., it does not intersect any portion of the unstable power swing region), therefore it meets PRC-026-1 – Attachment B, Criterion A, No. 1.

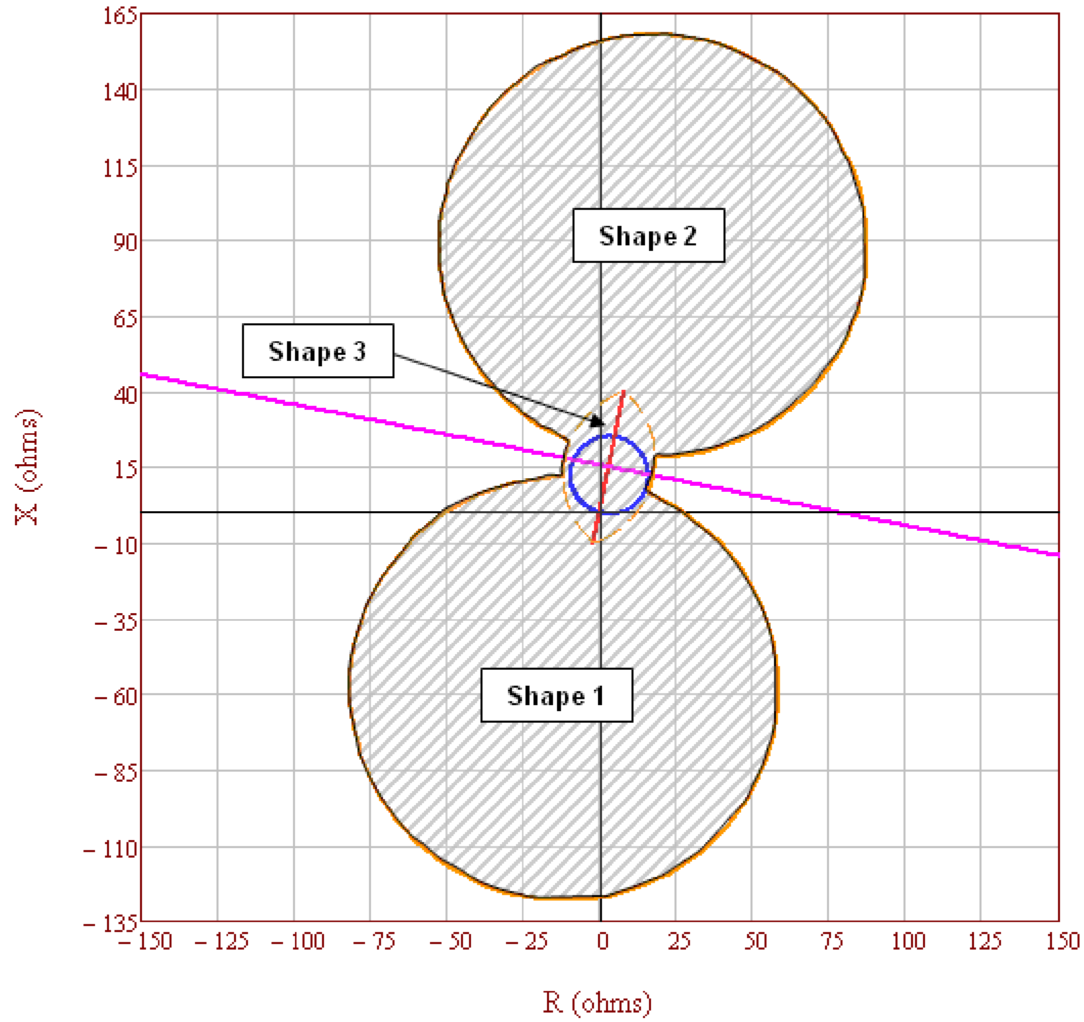


Figure 2: Full graphic of the unstable power swing region formed by the union of the three shapes in the impedance (R-X) plane: Shape 1) Lower loss-of-synchronism circle, Shape 2) Upper loss-of-synchronism circle, and Shape 3) Lens. The mho element characteristic is completely contained within the unstable power swing region, therefore it meets PRC-26-1 – Attachment B, Criterion A, No.1.

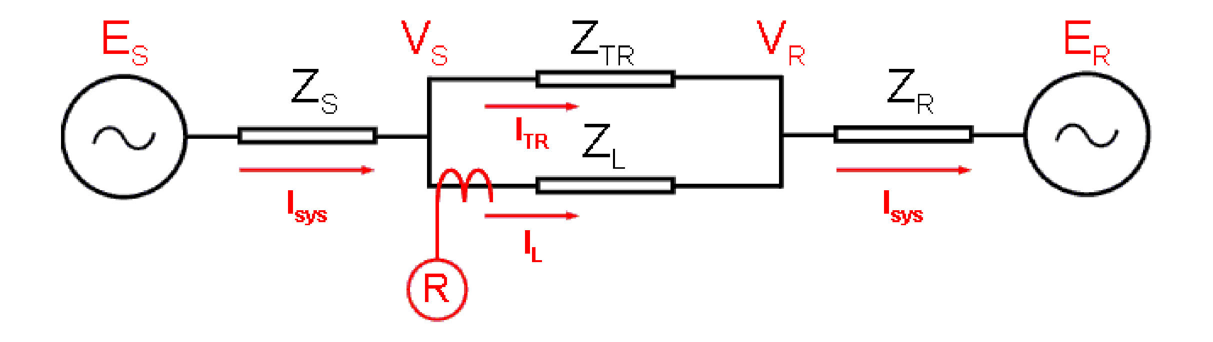


Figure 3: System impedances as seen by Relay R (voltage connections are not shown).

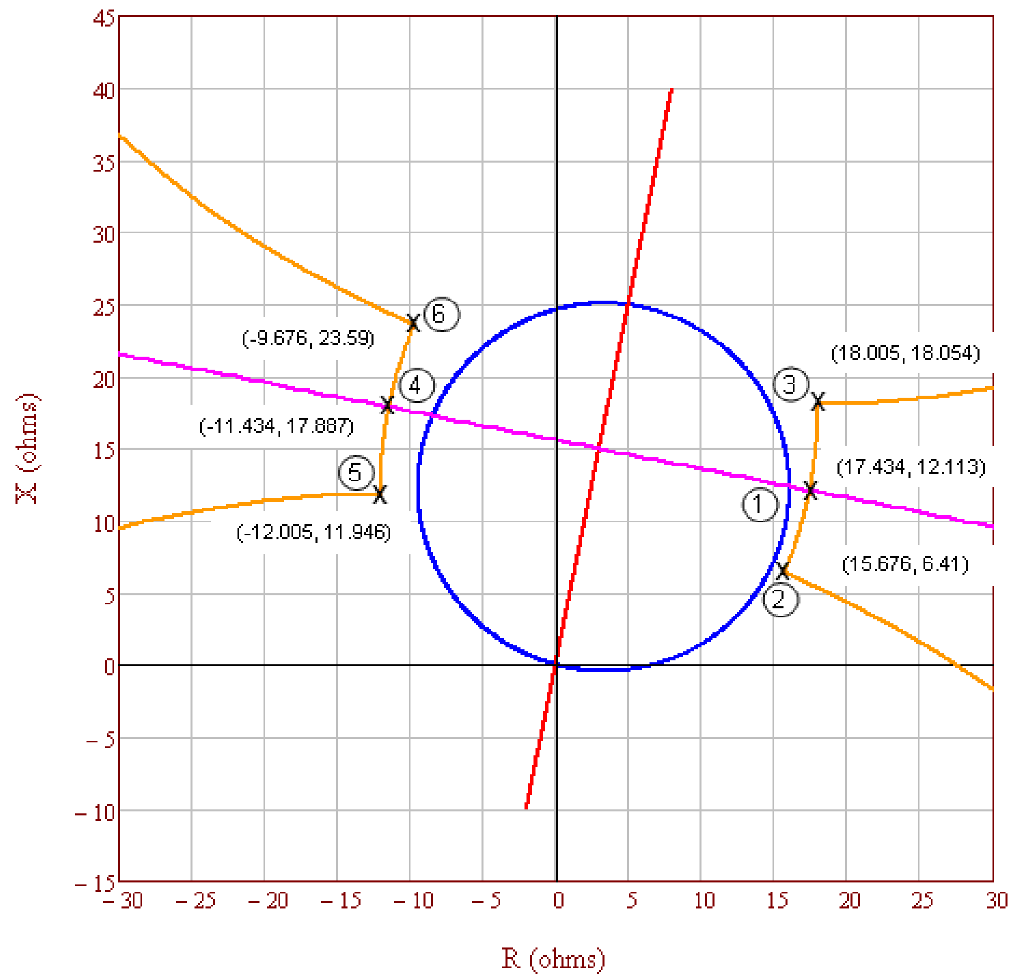


Figure 4: The defining unstable power swing region points where the lens shape intersects the lower and upper loss-of-synchronism circle shapes and where the lens intersects the equal EMF (electromotive force) power swing.

	Left Side Coordinates		Right Side Coordinates	
E_S / E_R Voltage Ratio	R	+ jX	R	+ jX
0.7	**-12.005**	**11.946**	**15.676**	**6.41**
0.72	-12.004	12.407	15.852	6.836
0.74	-11.996	12.857	16.018	7.255
0.76	-11.982	13.298	16.175	7.667
0.78	-11.961	13.729	16.321	8.073
0.8	-11.935	14.151	16.459	8.472
0.82	-11.903	14.563	16.589	8.865
0.84	-11.867	14.966	16.71	9.251
0.86	-11.826	15.361	16.824	9.631
0.88	-11.78	15.746	16.93	10.004
0.9	-11.731	16.123	17.03	10.371
0.92	-11.678	16.492	17.123	10.732
0.94	-11.621	16.852	17.209	11.086
0.96	-11.562	17.205	17.29	11.435
0.98	-11.499	17.55	17.364	11.777
1	**-11.434**	**17.887**	**17.434**	**12.113**
1.0286	-11.336	18.356	17.524	12.584
1.0572	-11.234	18.81	17.604	13.043
1.0858	-11.127	19.251	17.675	13.49
1.1144	-11.017	19.677	17.738	13.926
1.143	-10.904	20.091	17.792	14.351
1.1716	-10.788	20.491	17.84	14.766
1.2002	-10.67	20.88	17.88	15.17
1.2288	-10.55	21.256	17.914	15.564
1.2574	-10.428	21.621	17.942	15.948
1.286	-10.304	21.975	17.964	16.322
1.3146	-10.18	22.319	17.981	16.687
1.3432	-10.054	22.652	17.993	17.043
1.3718	-9.928	22.976	18.001	17.39
1.4004	-9.801	23.29	18.005	17.728
1.429	**-9.676**	**23.59**	**18.005**	**18.054**

Figure 5: Full table of 31 detailed lens shape point calculations. The bold highlighted rows correspond to the detailed calculations in Tables 2-7.

Table 2: Example Calculation (Lens Point 1)	
This example is for calculating the impedance the first point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 120 degrees. See Figures 3 and 4.	
Eq. (6)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$

Table 2: Example Calculation (Lens Point 1)			
	$E_S = \dfrac{230{,}000\angle 120^\circ\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120^\circ\ V$		
Eq. (7)	$E_R = \dfrac{V_{LL}\angle 0^\circ}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0^\circ\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0^\circ\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (8)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (9)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (10)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120^\circ\ V - 132{,}791\angle 0^\circ\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 71.3^\circ\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (11)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		

Table 2: Example Calculation (Lens Point 1)			
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4+j20) \times 10^{10}\ \Omega}{(4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.			
Eq. (12)	$V_S = E_S - (Z_S \times I_{sys})$		
	$V_S = 132{,}791\angle 120°\ V - [(2+j10)\ \Omega \times 4{,}511\angle 71.3°\ A]$		
	$V_S = 95{,}757\angle 106.1°\ V$		
The impedance seen by the relay on Z_L.			
Eq. (13)	$Z_{L-Relay} = \frac{V_S}{I_L}$		
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$		
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$		

Table 3: Example Calculation (Lens Point 2)			
This example is for calculating the impedance second point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (14)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 70\%$		
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 120°\ V$		
Eq. (15)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		

Table 3: Example Calculation (Lens Point 2)	
Total impedance between the generators.	
Eq. (16)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$
	$Z_{total} = \dfrac{\left((4+j20)\ \Omega \times (4+j20) \times 10^{10}\ \Omega\right)}{\left((4+j20)\ \Omega + (4+j20) \times 10^{10}\ \Omega\right)}$
	$Z_{total} = 4 + j20\ \Omega$
Total system impedance.	
Eq. (17)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$
	$Z_{sys} = 10 + j50\ \Omega$
Total system current from sending-end source.	
Eq. (18)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \dfrac{92{,}953.7\angle 120°\ V - 132{,}791\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 77°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (19)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 77°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 77°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (20)	$V_S = E_S - \left(Z_S \times I_{sys}\right)$
	$V_S = 92{,}953\angle 120°\ V - [(2 + j10\ )\Omega \times 3{,}854\angle 77°\ A]$
	$V_S = 65{,}271\angle 99°\ V$
The impedance seen by the relay on Z_L.	
Eq. (21)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$

Table 3: Example Calculation (Lens Point 2)	
	$Z_{L-Relay} = \dfrac{65{,}271\angle 99°\ V}{3{,}854\angle 77°\ A}$
	$Z_{L-Relay} = 15.676 + j6.41\ \Omega$

Table 4: Example Calculation (Lens Point 3)			
This example is for calculating the impedance third point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 120 degrees. See Figures 3 and 4.			
Eq. (22)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (23)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (24)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (25)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		

Table 4: Example Calculation (Lens Point 3)	
Total system current from sending-end source.	
Eq. (26)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 92{,}953.7\angle 0°\ V}{(10 + j50)\ \Omega}$
	$I_{sys} = 3{,}854\angle 65.5°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (27)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 65.5°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 65.5°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (28)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10)\ \Omega \times 3{,}854\angle 65.5°\ A]$
	$V_S = 98{,}265\angle 110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (29)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle 110.6°\ V}{3{,}854\angle 65.5°\ A}$
	$Z_{L-Relay} = 18.005 + j18.054\ \Omega$

Table 5: Example Calculation (Lens Point 4)	
This example is for calculating the impedance fourth point of the lens characteristic. Equal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) leading the receiving-end voltage (E_R) by 240 degrees. See Figures 3 and 4.	
Eq. (30)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$

Table 5: Example Calculation (Lens Point 4)			
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (31)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (32)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (33)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (34)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 240°\ V - 132{,}791\angle 0°\ V}{(10 + j50\ )\Omega}$		
	$I_{sys} = 4{,}511\angle 131.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (35)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 131.1°\ A \times \dfrac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 131.1°\ A$		

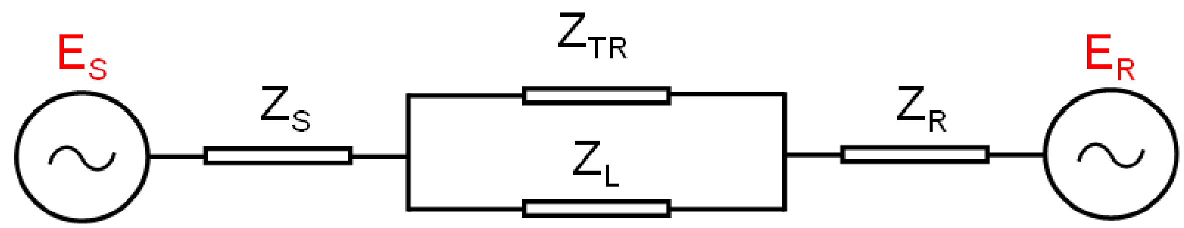
Table 5: Example Calculation (Lens Point 4)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (36)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 4{,}511\angle 131.1°\ A]$
	$V_S = 95{,}756\angle -106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (37)	$Z_{L-Relay} = \dfrac{V_S}{I_L}$
	$Z_{L-Relay} = \dfrac{95{,}756\angle -106.1°\ V}{4{,}511\angle 131.1°\ A}$
	$Z_{L-Relay} = -11.434 + j17.887\ \Omega$

Table 6: Example Calculation (Lens Point 5)			
This example is for calculating the impedance fifth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the sending-end voltage (E_S) at 70% of the receiving-end voltage (E_R) and leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (38)	$E_S = \dfrac{V_{LL}\angle 240°}{\sqrt{3}} \times 70\%$		
	$E_S = \dfrac{230{,}000\angle 240°\ V}{\sqrt{3}} \times 0.70$		
	$E_S = 92{,}953.7\angle 240°\ V$		
Eq. (39)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (40)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		

Table 6: Example Calculation (Lens Point 5)	
	$Z_{total} = \frac{\left((4+j20)\,\Omega \times (4+j20)\times 10^{10}\,\Omega\right)}{\left((4+j20)\,\Omega + (4+j20)\times 10^{10}\,\Omega\right)}$
	$Z_{total} = 4 + j20\,\Omega$
Total system impedance.	
Eq. (41)	$Z_{sys} = Z_S + Z_{total} + Z_R$
	$Z_{sys} = (2 + j10\,\Omega) + (4 + j20\,\Omega) + (4 + j20\,\Omega)$
	$Z_{sys} = 10 + j50\,\Omega$
Total system current from sending-end source.	
Eq. (42)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$
	$I_{sys} = \frac{92{,}953.7\angle 240°\,V - 132{,}791\angle 0°\,V}{10 + j50\,\Omega}$
	$I_{sys} = 3{,}854\angle 125.5°\,A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (43)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 125.5°\,A \times \frac{(4+j20)\times 10^{10}\,\Omega}{(4+j20)\,\Omega + (4+j20)\times 10^{10}\,\Omega}$
	$I_L = 3{,}854\angle 125.5°\,A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (44)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 92{,}953.7\angle 240°\,V - [(2 + j10\,)\,\Omega \times 3{,}854\angle 125.5°\,A]$
	$V_S = 65{,}270.5\angle -99.4°\,V$
The impedance seen by the relay on Z_L.	
Eq. (45)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{65{,}270.5\angle -99.4°\,V}{3{,}854\angle 125.5°\,A}$
	$Z_{L-Relay} = -12.005 + j11.946\,\Omega$

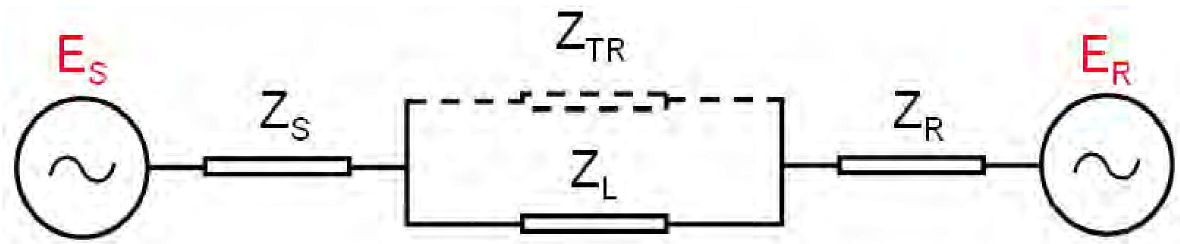
Table 7: Example Calculation (Lens Point 6)			
This example is for calculating the impedance sixth point of the lens characteristic. Unequal source voltages are used for the 230 kV (base) line with the receiving-end voltage (E_R) at 70% of the sending-end voltage (E_S) and the sending-end voltage leading the receiving-end voltage by 240 degrees. See Figures 3 and 4.			
Eq. (46)	$E_S = \frac{V_{LL}\angle 240°}{\sqrt{3}}$		
	$E_S = \frac{230{,}000\angle 240°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 240°\ V$		
Eq. (47)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 70\%$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 0.70$		
	$E_R = 92{,}953.7\angle 0°\ V$		
Positive sequence impedance data (with transfer impedance Z_{TR} set to a large value).			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (48)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (49)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (50)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 240°\ V - 92{,}953.7\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 3{,}854\angle 137.1°\ A$		

Table 7: Example Calculation (Lens Point 6)	
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (51)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 3{,}854\angle 137.1°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$
	$I_L = 3{,}854\angle 137.1°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (52)	$V_S = E_S - (Z_S \times I_L)$
	$V_S = 132{,}791\angle 240°\ V - [(2 + j10\ )\ \Omega \times 3{,}854\angle 137.1°\ A]$
	$V_S = 98{,}265\angle -110.6°\ V$
The impedance seen by the relay on Z_L.	
Eq. (53)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{98{,}265\angle -110.6°\ V}{3{,}854\angle 137.1°\ A}$
	$Z_{L-Relay} = -9.676 + j23.59\ \Omega$



$$Z_{Total} = Z_S + \frac{Z_L \cdot Z_{TR}}{Z_L + Z_{TR}} + Z_R$$

Figure 6: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, line impedance Z_L, and parallel transfer impedance Z_{TR}.



$$Z_{sys} = Z_S + Z_L + Z_R$$

Figure 7: Reduced two bus system with sending-end source impedance Z_S, receiving-end source impedance Z_R, and line impedance Z_L with the parallel transfer impedance Z_{TR} removed.

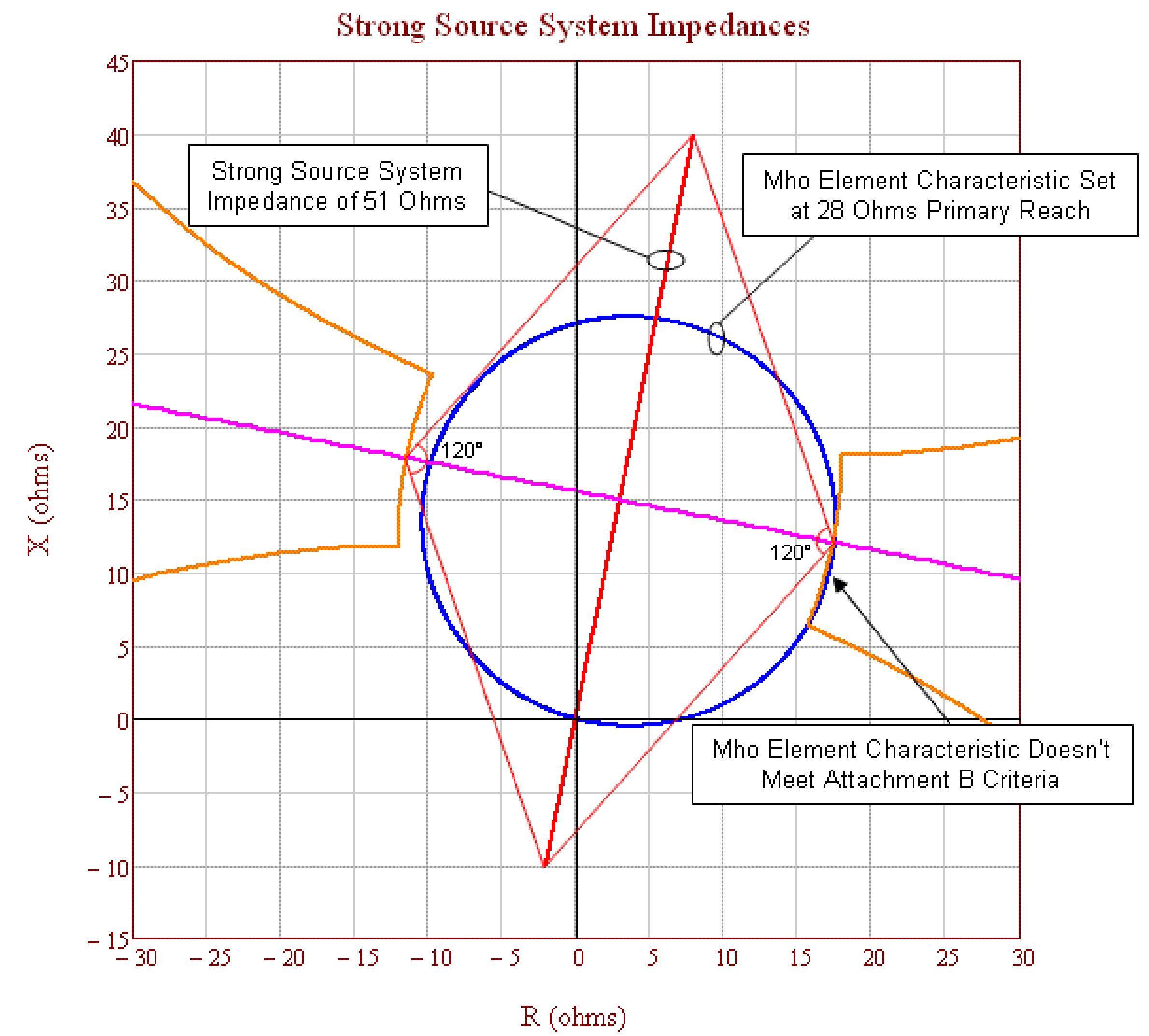


Figure 8: A strong-source system with a line impedance of $Z_L = 20.4$ ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) does not meet the PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 8 above represents a heavily-loaded system with all generation in service and all transmission BES Elements in their normal operating state. The mho element characteristic (set at 137% of Z_L) extends into the unstable power swing region (i.e., the orange characteristic). Using the strongest source system is more conservative because it shrinks the unstable power swing region, bringing it closer to the mho element characteristic. This figure also graphically represents the effect of a system strengthening over time and this is the reason for re-evaluation if the relay has not been evaluated in the last five calendar years. Figure 9 below depicts a relay that meets the PRC-026-1 – Attachment B, Criterion A. Figure 8 depicts the same relay with the same setting five years later, where each source has strengthened by about 10% and now the same mho element characteristic does not meet Criterion A.

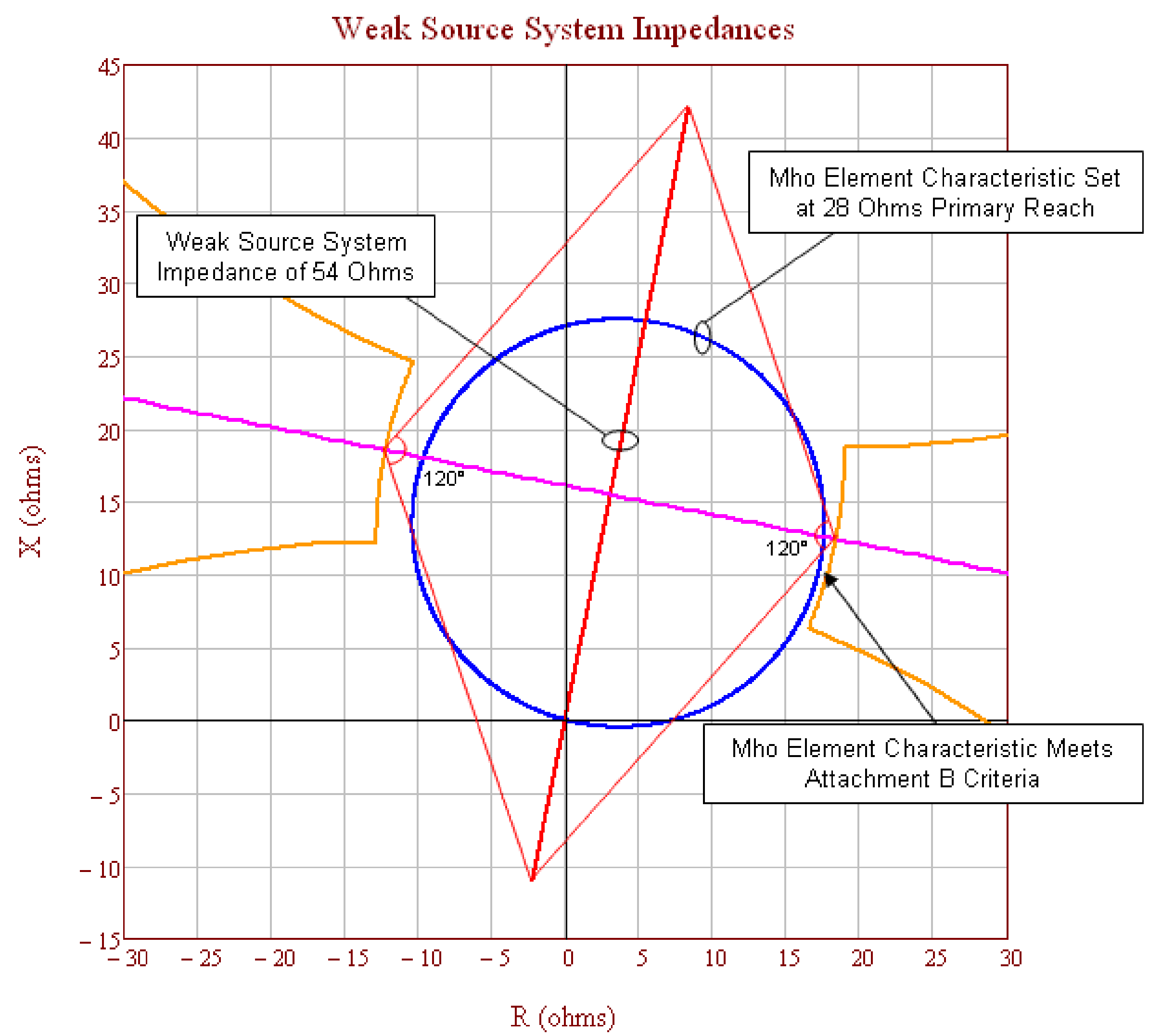


Figure 9: A weak-source system with a line impedance of Z_L = 20.4 ohms (i.e., the thicker red line). This mho element characteristic (i.e., the blue circle) meets the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region (i.e., the orange characteristic).

Figure 9 above represents a lightly-loaded system, using a minimum generation profile. The mho element characteristic (set at 137% of Z_L) does not extend into the unstable power swing region (i.e., the orange characteristic). Using a weaker source system expands the unstable power swing region away from the mho element characteristic.

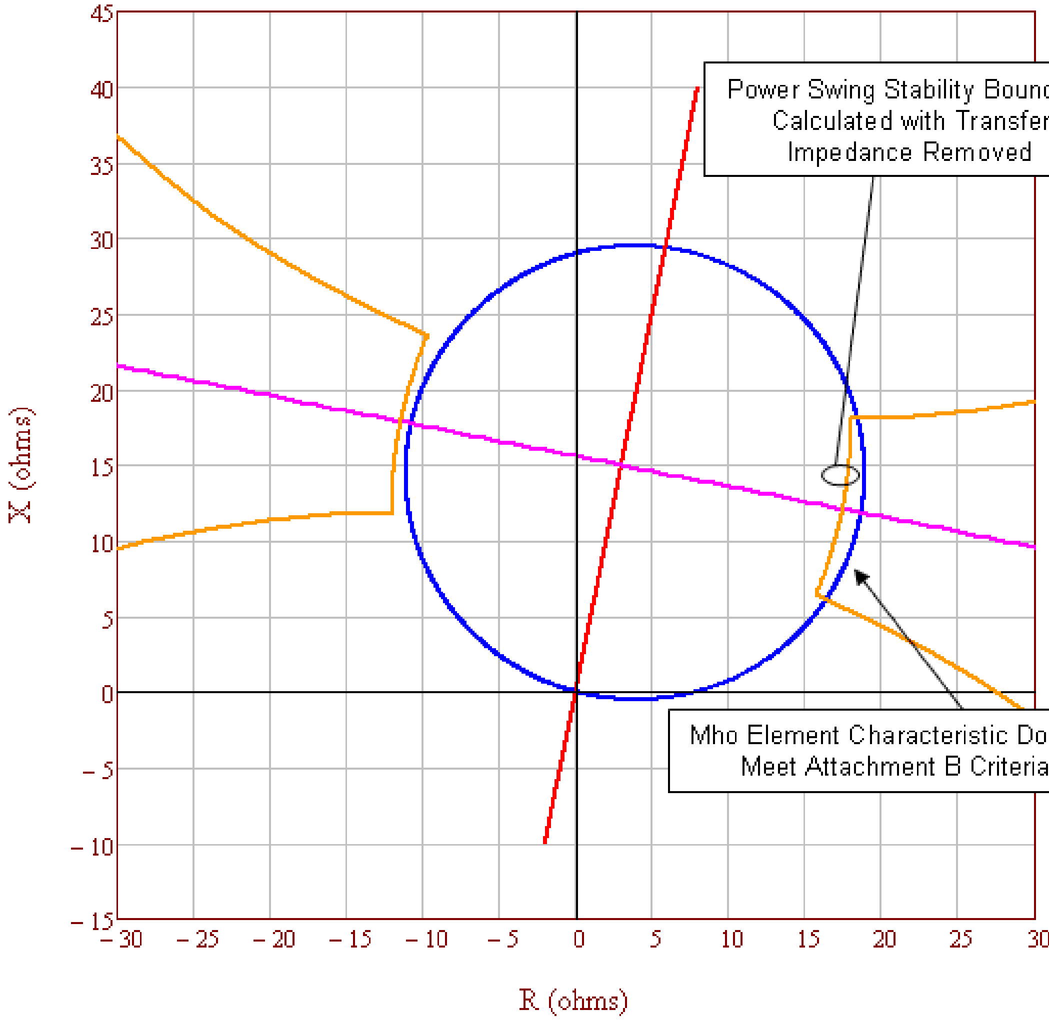


Figure 10: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance removed. This relay mho element characteristic (i.e., the blue circle) does not meet PRC-026-1 – Attachment B, Criterion A because it is not completely contained within the unstable power swing region.

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
Calculations for the point at 120 degrees with equal source impedances. The total system current equals the line current. See Figure 10.	
Eq. (54)	$E_S = \frac{V_{LL}\angle 120°}{\sqrt{3}}$
	$E_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}}$
	$E_S = 132{,}791\angle 120°\ V$

Table 8: Example Calculation (Parallel Transfer Impedance Removed)			
Eq. (55)	$E_R = \frac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
Total impedance between the generators.			
Eq. (56)	$Z_{total} = \frac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \frac{\left((4 + j20)\ \Omega \times (4 + j20) \times 10^{10}\ \Omega\right)}{\left((4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega\right)}$		
	$Z_{total} = 4 + j20\ \Omega$		
Total system impedance.			
Eq. (57)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (4 + j20)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 10 + j50\ \Omega$		
Total system current from sending-end source.			
Eq. (58)	$I_{sys} = \frac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \frac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{10 + j50\ \Omega}$		
	$I_{sys} = 4{,}511\angle 71.3°\ A$		
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.			
Eq. (59)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$		
	$I_L = 4{,}511\angle 71.3°\ A \times \frac{(4 + j20) \times 10^{10}\ \Omega}{(4 + j20)\ \Omega + (4 + j20) \times 10^{10}\ \Omega}$		
	$I_L = 4{,}511\angle 71.3°\ A$		

Table 8: Example Calculation (Parallel Transfer Impedance Removed)	
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (60)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}511\angle 71.3°\ A]$
	$V_S = 95{,}757\angle 106.1°\ V$
The impedance seen by the relay on Z_L.	
Eq. (61)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{95{,}757\angle 106.1°\ V}{4{,}511\angle 71.3°\ A}$
	$Z_{L-Relay} = 17.434 + j12.113\ \Omega$

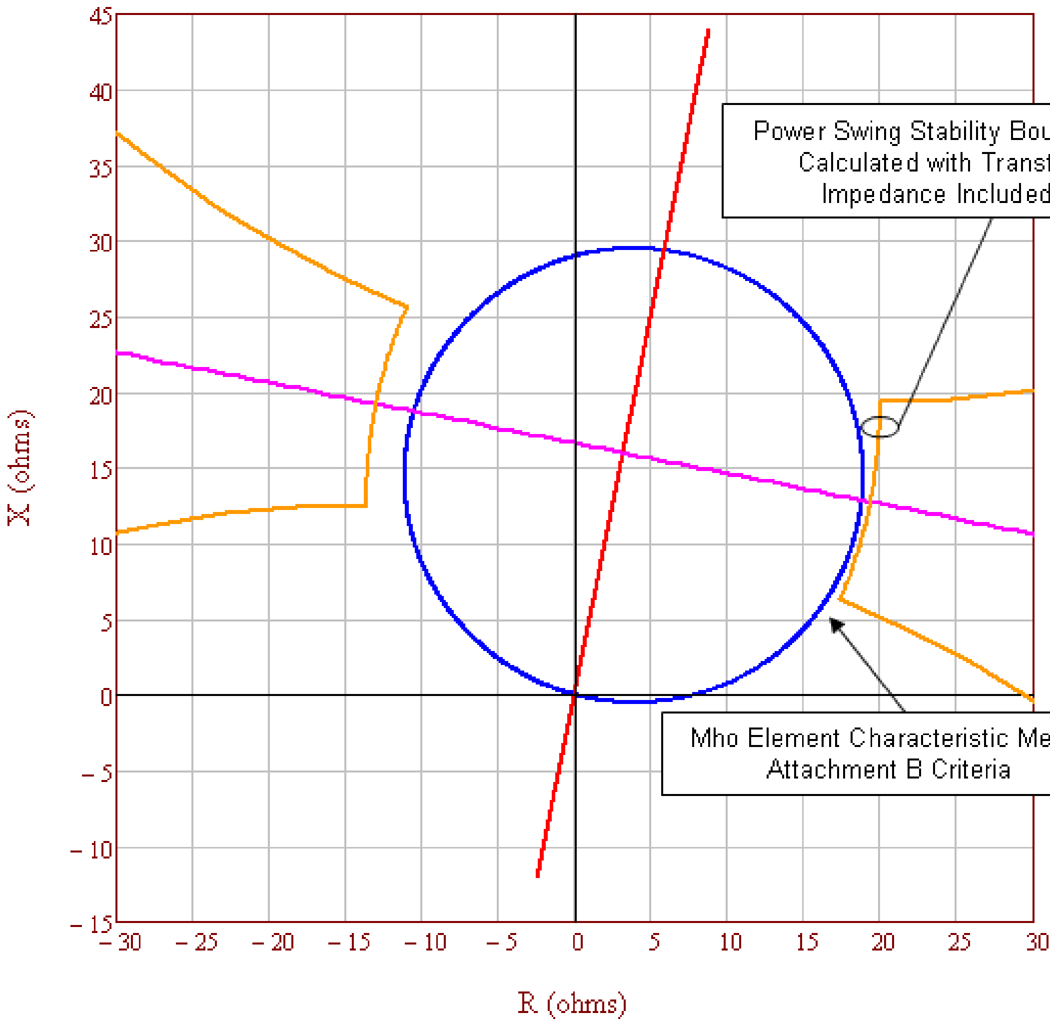


Figure 11: This is an example of an unstable power swing region (i.e., the orange characteristic) with the parallel transfer impedance included causing the mho element characteristic (i.e., the blue circle) to appear to meet the PRC-026-1 – Attachment B, Criterion A because it is completely contained within the unstable power swing region. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

In Figure 11 above, the parallel transfer impedance is 5 times the line impedance. The unstable power swing region has expanded out beyond the mho element characteristic due to the infeed effect from the parallel current through the parallel transfer impedance, thus allowing the mho element characteristic to appear to meet the PRC-026-1 – Attachment B, Criterion A. Including the parallel transfer impedance in the calculation is not allowed by the PRC-026-1 – Attachment B, Criterion A.

Table 9: Example Calculation (Parallel Transfer Impedance Included)			
Calculations for the point at 120 degrees with equal source impedances. The total system current does not equal the line current. See Figure 11.			
Eq. (62)	$E_S = \dfrac{V_{LL}\angle 120°}{\sqrt{3}}$		
	$E_S = \dfrac{230{,}000\angle 120°\ V}{\sqrt{3}}$		
	$E_S = 132{,}791\angle 120°\ V$		
Eq. (63)	$E_R = \dfrac{V_{LL}\angle 0°}{\sqrt{3}}$		
	$E_R = \dfrac{230{,}000\angle 0°\ V}{\sqrt{3}}$		
	$E_R = 132{,}791\angle 0°\ V$		
Given impedance data.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 5$		
	$Z_{TR} = (4 + j20)\ \Omega \times 5$		
	$Z_{TR} = 20 + j100\ \Omega$		
Total impedance between the generators.			
Eq. (64)	$Z_{total} = \dfrac{(Z_L \times Z_{TR})}{(Z_L + Z_{TR})}$		
	$Z_{total} = \dfrac{(4 + j20)\ \Omega \times (20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$		
	$Z_{total} = 3.333 + j16.667\ \Omega$		
Total system impedance.			
Eq. (65)	$Z_{sys} = Z_S + Z_{total} + Z_R$		
	$Z_{sys} = (2 + j10)\ \Omega + (3.333 + j16.667)\ \Omega + (4 + j20)\ \Omega$		
	$Z_{sys} = 9.333 + j46.667\ \Omega$		
Total system current from sending-end source.			
Eq. (66)	$I_{sys} = \dfrac{E_S - E_R}{Z_{sys}}$		
	$I_{sys} = \dfrac{132{,}791\angle 120°\ V - 132{,}791\angle 0°\ V}{9.333 + j46.667\ \Omega}$		

Table 9: Example Calculation (Parallel Transfer Impedance Included)	
	$I_{sys} = 4{,}833\angle 71.3°\ A$
The current, as measured by the relay on Z_L (Figure 3), is only the current flowing through that line as determined by using the current divider equation.	
Eq. (67)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$
	$I_L = 4{,}833\angle 71.3°\ A \times \frac{(20 + j100)\ \Omega}{(4 + j20)\ \Omega + (20 + j100)\ \Omega}$
	$I_L = 4{,}027.4\angle 71.3°\ A$
The voltage, as measured by the relay on Z_L (Figure 3), is the voltage drop from the sending-end source through the sending-end source impedance.	
Eq. (68)	$V_S = E_S - (Z_S \times I_{sys})$
	$V_S = 132{,}791\angle 120°\ V - [(2 + j10\ \Omega) \times 4{,}833\angle 71.3°\ A]$
	$V_S = 93{,}417\angle 104.7°\ V$
The impedance seen by the relay on Z_L.	
Eq. (69)	$Z_{L-Relay} = \frac{V_S}{I_L}$
	$Z_{L-Relay} = \frac{93{,}417\angle 104.7°\ V}{4{,}027\angle 71.3°\ A}$
	$Z_{L-Relay} = 19.366 + j12.767\ \Omega$

Table 10: Percent Increase of a Lens Due To Parallel Transfer Impedance.	
The following demonstrates the percent size increase of the lens characteristic for Z_{TR} in multiples of Z_L with the parallel transfer impedance included.	
Z_{TR} in multiples of Z_L	Percent increase of lens with equal EMF sources (Infinite source as reference)
Infinite	N/A
1000	0.05%
100	0.46%
10	4.63%
5	9.27%
2	23.26%
1	46.76%
0.5	94.14%
0.25	189.56%

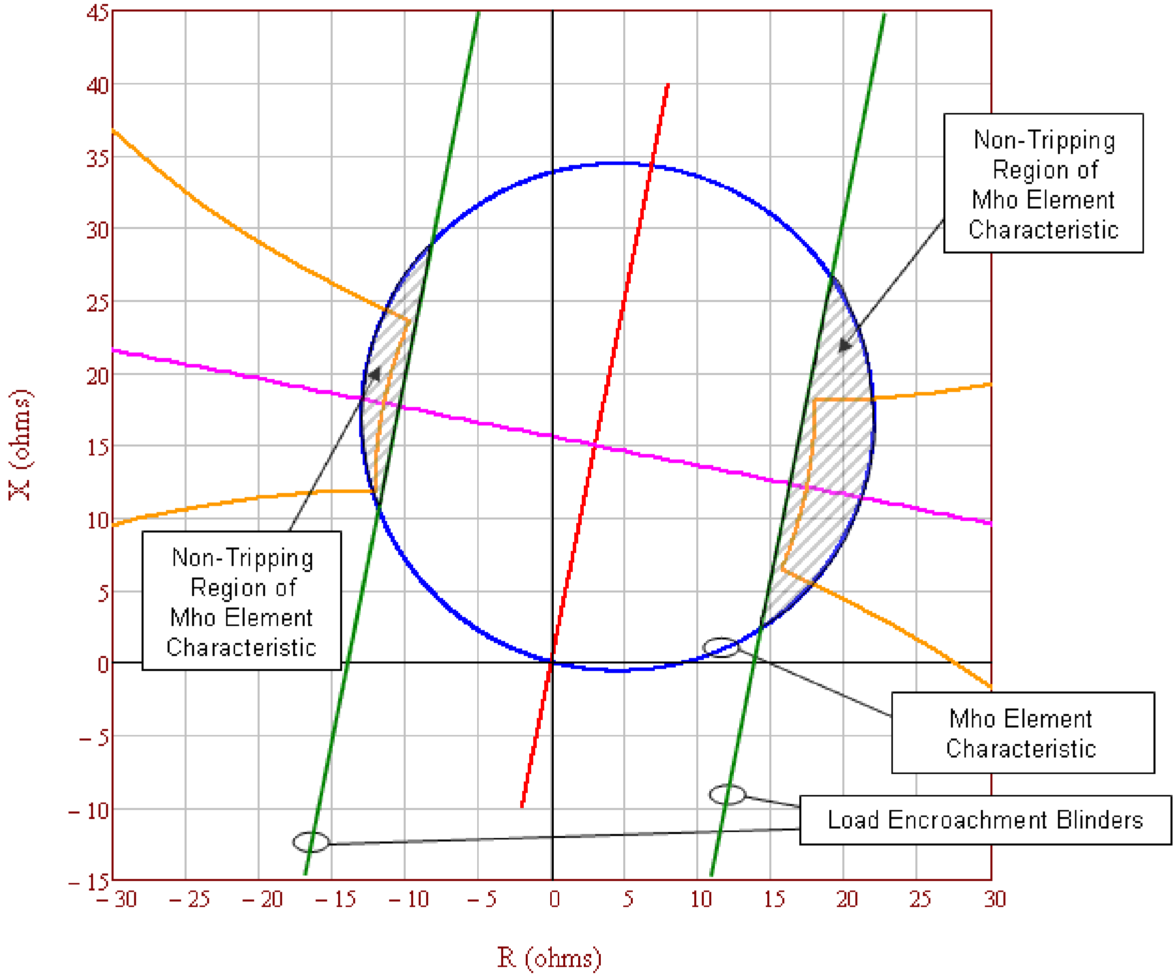


Figure 12: The tripping portion of the mho element characteristic (i.e., the blue circle) not blocked by load encroachment (i.e., the parallel green lines) is completely contained within the unstable power swing region (i.e., the orange characteristic). Therefore, the mho element characteristic meets the PRC-026-1 – Attachment B, Criterion A.

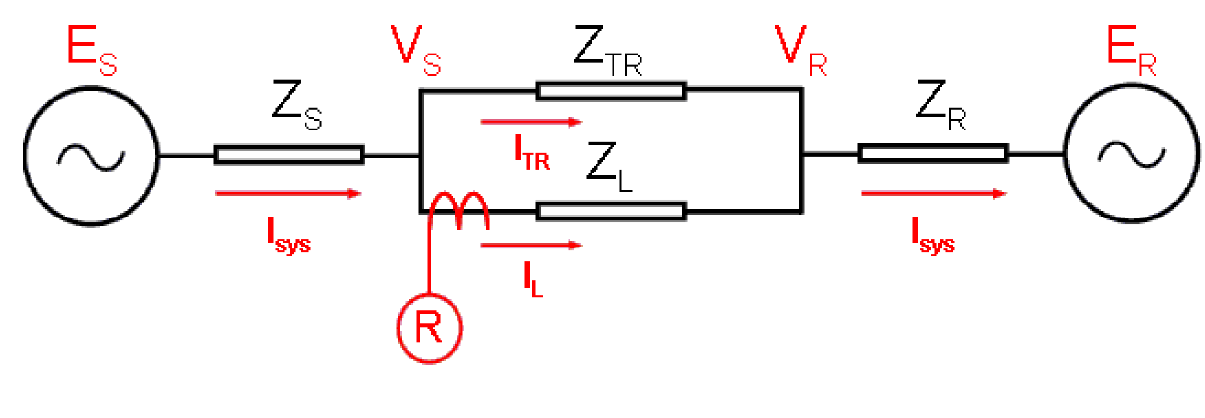


Figure 13: The infeed diagram shows the impedance in front of the relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.

Table 11: Calculations (System Apparent Impedance in the forward direction)				
The following equations are provided for calculating the apparent impedance back to the E_R source voltage as seen by relay R. Infeed equations from V_S to source E_R where $E_R = 0$. See Figure 13.				
Eq. (70)	$I_L = \dfrac{V_S - V_R}{Z_L}$			
Eq. (71)	$I_{sys} = \dfrac{V_R - E_R}{Z_R}$			
Eq. (72)	$I_{sys} = I_L + I_{TR}$			
Eq. (73)	$I_{sys} = \dfrac{V_R}{Z_R}$	Since $E_R = 0$	Rearranged:	$V_R = I_{sys} \times Z_R$
Eq. (74)	$I_L = \dfrac{V_S - I_{sys} \times Z_R}{Z_L}$			
Eq. (75)	$I_L = \dfrac{V_S - [(I_L + I_{TR}) \times Z_R]}{Z_L}$			
Eq. (76)	$V_S = (I_L \times Z_L) + (I_L \times Z_R) + (I_{TR} \times Z_R)$			
Eq. (77)	$Z_{Relay} = \dfrac{V_S}{I_L} = Z_L + Z_R + \dfrac{I_{TR} \times Z_R}{I_L} = Z_L + Z_R \times \left(1 + \dfrac{I_{TR}}{I_L}\right)$			
Eq. (78)	$I_{TR} = I_{sys} \times \dfrac{Z_L}{Z_L + Z_{TR}}$			
Eq. (79)	$I_L = I_{sys} \times \dfrac{Z_{TR}}{Z_L + Z_{TR}}$			

Table 11: Calculations (System Apparent Impedance in the forward direction)	
Eq. (80)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$
The infeed equations shows the impedance in front of the relay R (Figure 13) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the forward direction becomes $Z_L + Z_R$.	
Eq. (81)	$Z_{Relay} = Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$

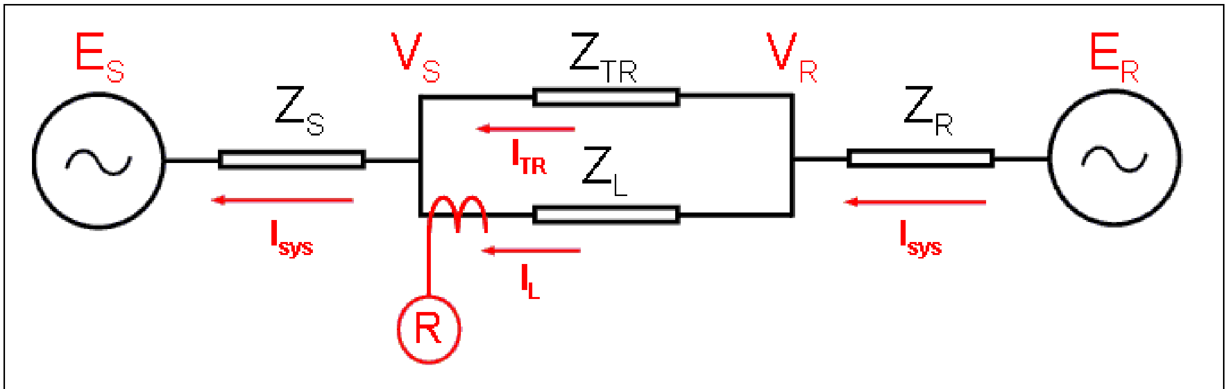


Figure 14: The infeed diagram shows the impedance behind relay R with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)				
The following equations are provided for calculating the apparent impedance back to the E_S source voltage as seen by relay R. Infeed equations from V_R back to source E_S where $E_S = 0$. See Figure 14.				
Eq. (82)	$I_L = \frac{V_R - V_S}{Z_L}$			
Eq. (83)	$I_{sys} = \frac{V_S - E_S}{Z_S}$			
Eq. (84)	$I_{sys} = I_L + I_{TR}$			
Eq. (85)	$I_{sys} = \frac{V_S}{Z_S}$	Since $E_s = 0$	Rearranged:	$V_S = I_{sys} \times Z_S$
Eq. (86)	$I_L = \frac{V_R - I_{sys} \times Z_S}{Z_L}$			

Table 12: Calculations (System Apparent Impedance in the Reverse Direction)		
Eq. (87)	$I_L = \frac{V_R - [(I_L + I_{TR}) \times Z_S]}{Z_L}$	
Eq. (88)	$V_R = (I_L \times Z_L) + (I_L \times Z_S) + (I_{TR} \times Z_{RS})$	
Eq. (89)	$Z_{Relay} = \frac{V_R}{I_L} = Z_L + Z_S + \frac{I_{TR} \times Z_S}{I_L} = Z_L + Z_S \times \left(1 + \frac{I_{TR}}{I_L}\right)$	
Eq. (90)	$I_{TR} = I_{sys} \times \frac{Z_L}{Z_L + Z_{TR}}$	
Eq. (91)	$I_L = I_{sys} \times \frac{Z_{TR}}{Z_L + Z_{TR}}$	
Eq. (92)	$\frac{I_{TR}}{I_L} = \frac{Z_L}{Z_{TR}}$	
The infeed equations shows the impedance behind relay R (Figure 14) with the parallel transfer impedance included. As the parallel transfer impedance approaches infinity, the impedances seen by the relay R in the reverse direction becomes Z_S.		
Eq. (93)	$Z_{Relay} = Z_L + Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	As seen by relay R at the receiving-end of the line.
Eq. (94)	$Z_{Relay} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)$	Subtract Z_L for relay R impedance as seen at sending-end of the line.

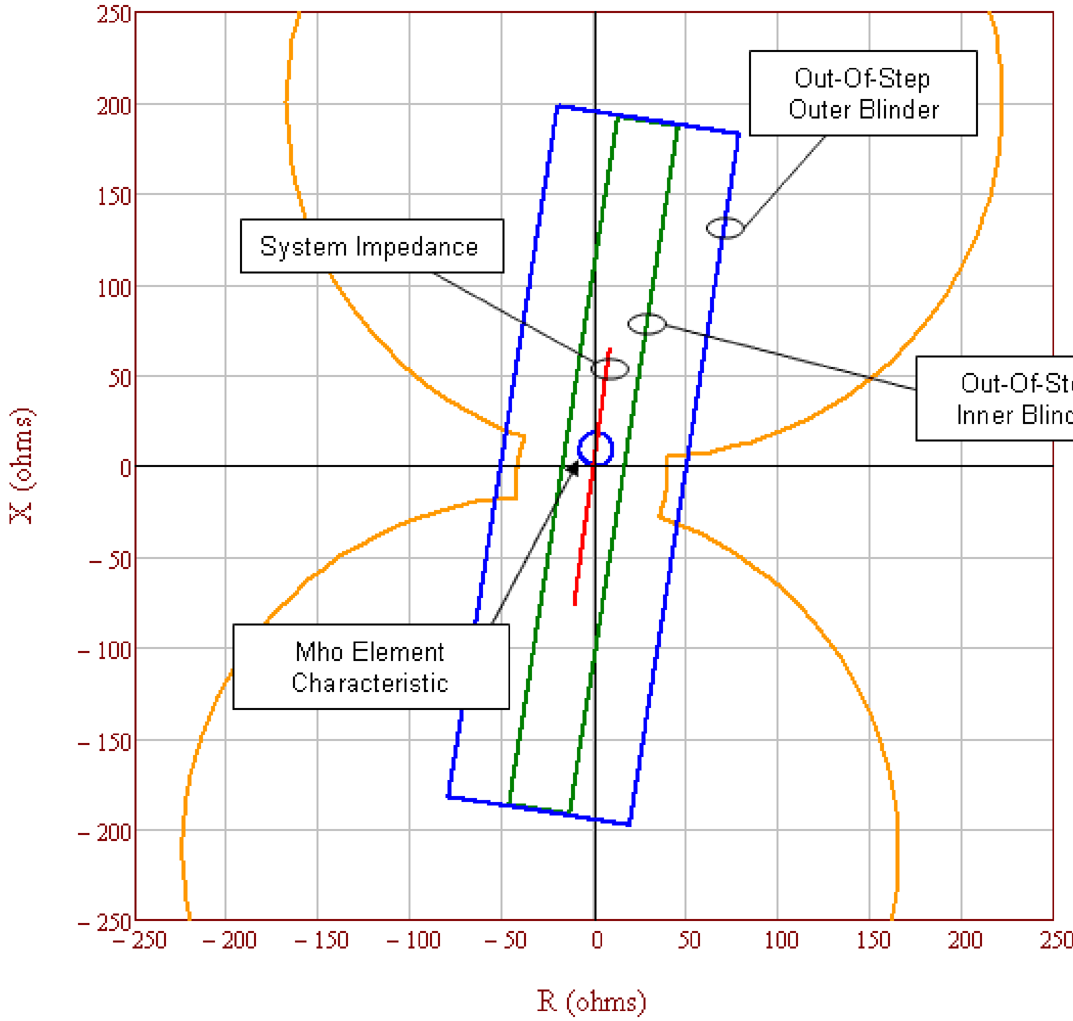


Figure 15: Out-of-step trip (OST) inner blinder (i.e., the parallel green lines) meets the PRC-026-1 – Attachment B, Criterion A because the inner OST blinder initiates tripping either On-The-Way-In or On-The-Way-Out. Since the inner blinder is completely contained within the unstable power swing region (i.e., the orange characteristic), it meets the PRC-026-1 – Attachment B, Criterion A.

Table 13: Example Calculation (Voltage Ratios)			
These calculations are based on the loss-of-synchronism characteristics for the cases of N < 1 and N > 1 as found in the *Application of Out-of-Step Blocking and Tripping Relays*, GER-3180, p. 12, Figure 3.[18] The GE illustration shows the formulae used to calculate the radius and center of the circles that make up the ends of the portion of the lens.			
Voltage ratio equations, source impedance equation with infeed formulae applied, and circle equations.			
Given:	$E_S = 0.7$	$E_R = 1.0$	
Eq. (95)	$N = \frac{\|E_S\|}{\|E_R\|} = \frac{0.7}{1.0} = 0.7$		
The total system impedance as seen by the relay with infeed formulae applied.			
Given:	$Z_S = 2 + j10\ \Omega$	$Z_L = 4 + j20\ \Omega$	$Z_R = 4 + j20\ \Omega$
Given:	$Z_{TR} = Z_L \times 10^{10}\ \Omega$		
	$Z_{TR} = (4 + j20) \times 10^{10}\ \Omega$		
Eq. (96)	$Z_{sys} = Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right) + \left[Z_L + Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right]$		
	$Z_{sys} = 10 + j50\ \Omega$		
The calculated coordinates of the lower loss-of-synchronism circle center.			
Eq. (97)	$Z_{C1} = -\left[Z_S \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] - \left[\frac{N^2 \times Z_{sys}}{1 - N^2}\right]$		
	$Z_{C1} = -\left[(2 + j10)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] - \left[\frac{0.7^2 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right]$		
	$Z_{C1} = -11.608 - j58.039\ \Omega$		
The calculated radius of the lower loss-of-synchronism circle.			
Eq. (98)	$r_a = \left\|\frac{N \times Z_{sys}}{1 - N^2}\right\|$		
	$r_a = \left\|\frac{0.7 \times (10 + j50)\ \Omega}{1 - 0.7^2}\right\|$		
	$r_a = 69.987\ \Omega$		
The calculated coordinates of the upper loss-of-synchronism circle center.			
Given:	$E_S = 1.0$	$E_R = 0.7$	

[18] http://store.gedigitalenergy.com/faq/Documents/Alps/GER-3180.pdf

Table 13: Example Calculation (Voltage Ratios)	
Eq. (99)	$N = \frac{\lvert E_S \rvert}{\lvert E_R \rvert} = \frac{1.0}{0.7} = 1.43$
Eq. (100)	$Z_{C2} = Z_L + \left[Z_R \times \left(1 + \frac{Z_L}{Z_{TR}}\right)\right] + \left[\frac{Z_{sys}}{N^2 - 1}\right]$
	$Z_{C2} = 4 + j20\ \Omega + \left[(4 + j20)\ \Omega \times \left(1 + \frac{(4 + j20)\ \Omega}{(4 + j20) \times 10^{10}\ \Omega}\right)\right] + \left[\frac{(10 + j50)\ \Omega}{1.43^2 - 1}\right]$
	$Z_{C2} = 17.608 + j88.039\ \Omega$
The calculated radius of the upper loss-of-synchronism circle.	
Eq. (101)	$r_b = \left\lvert\frac{N \times Z_{sys}}{N^2 - 1}\right\rvert$
	$r_b = \left\lvert\frac{1.43 \times (10 + j50)\ \Omega}{1.43^2 - 1}\right\rvert$
	$r_b = 69.987\ \Omega$

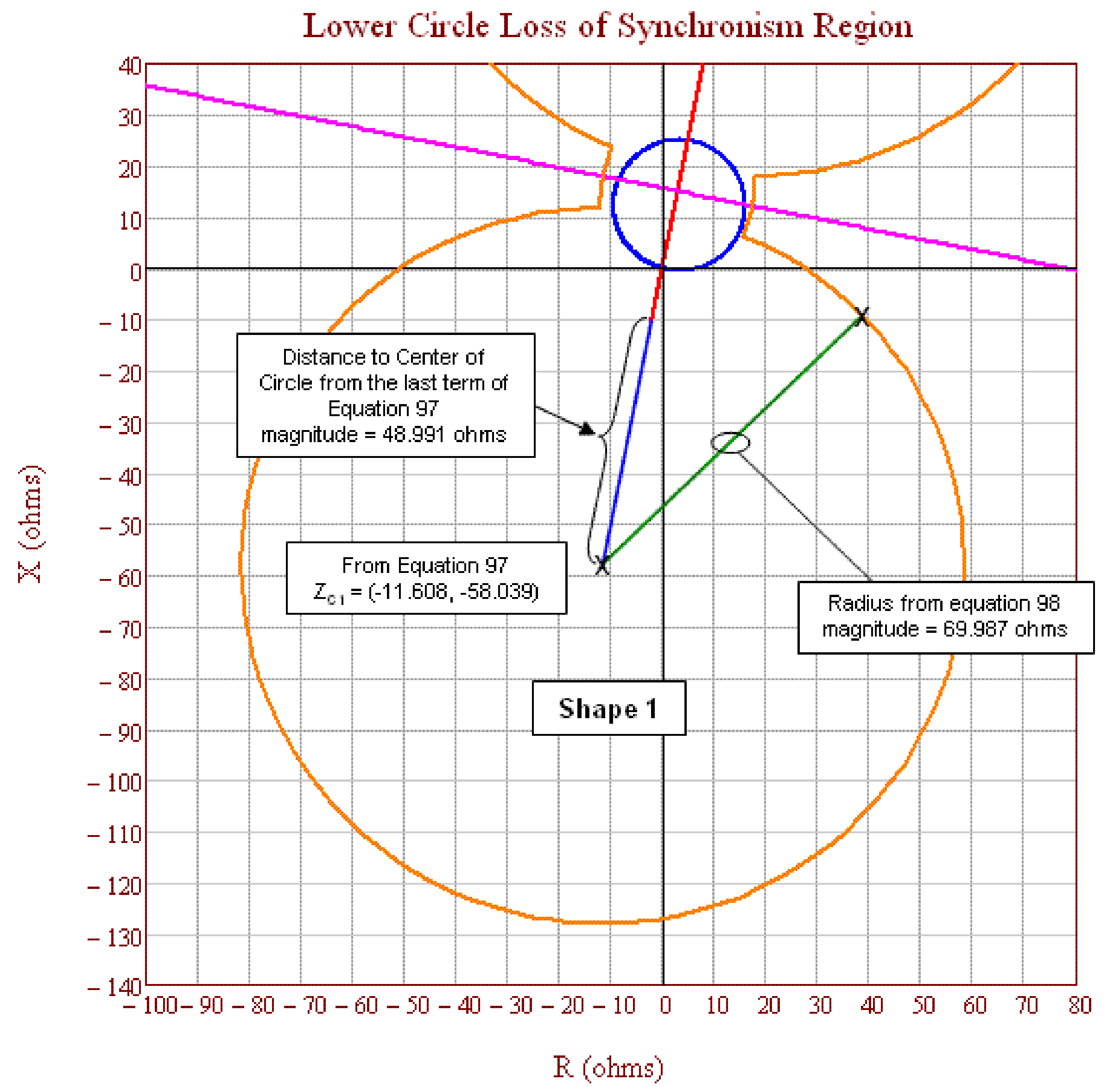


Figure 15a: Lower circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

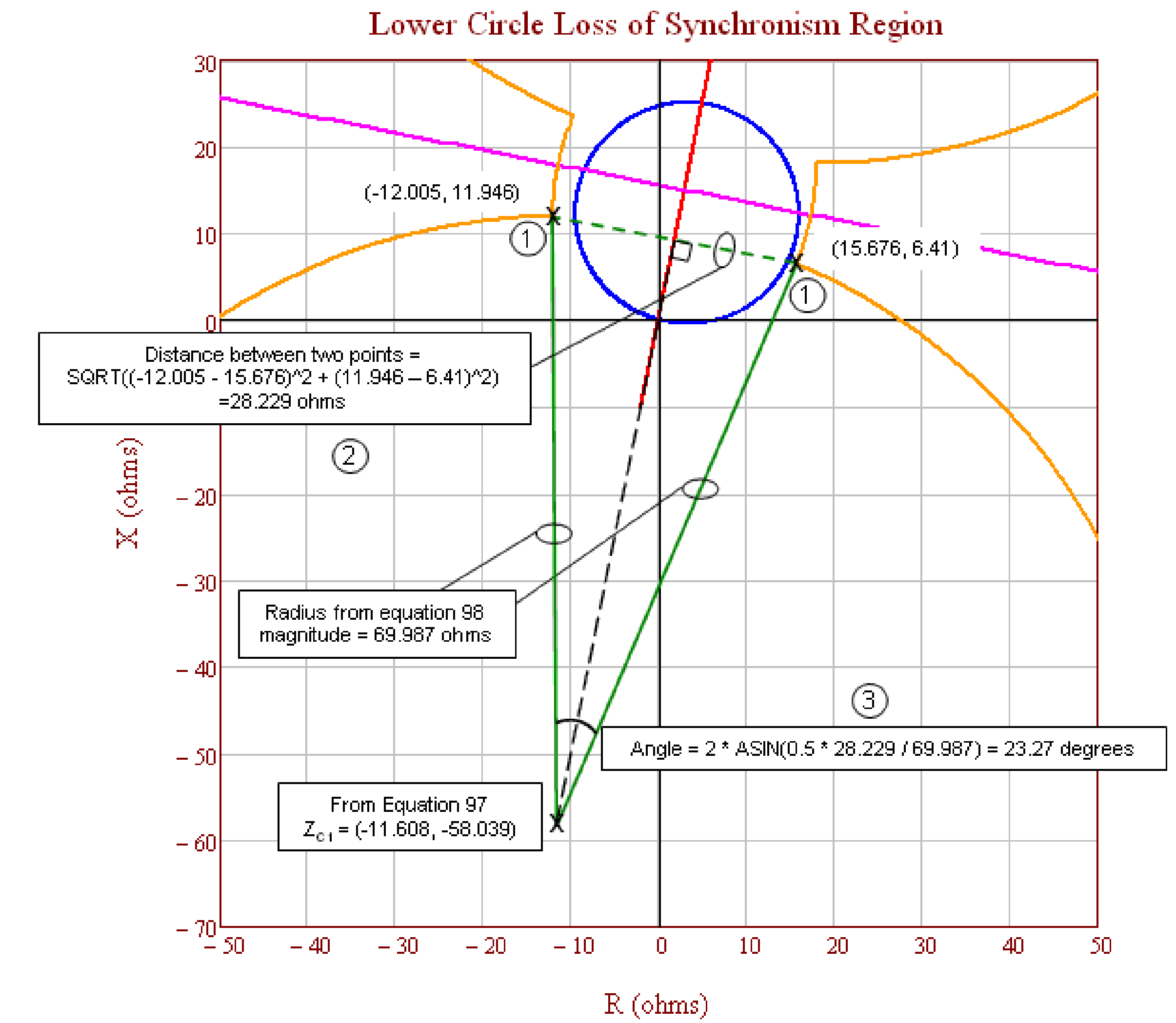


Figure 15b: Lower circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the lower circle loss-of-synchronism points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 0.7 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two lower circle loss-of-synchronism points identified in Step 1. 3) Calculate the angle of arc that connects the two lower circle loss-of-synchronism points identified in Step 1.

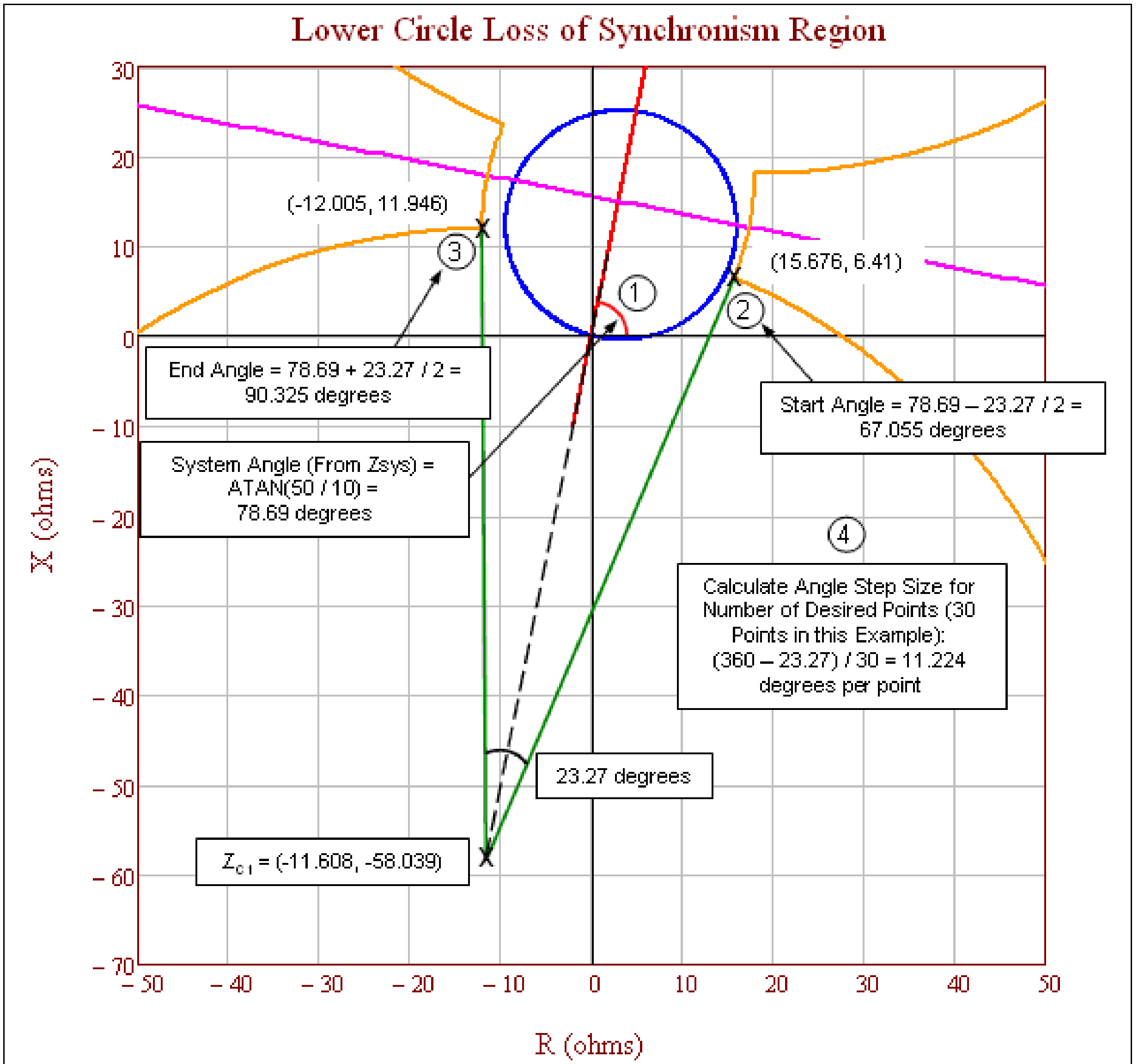


Figure 15c: Lower circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

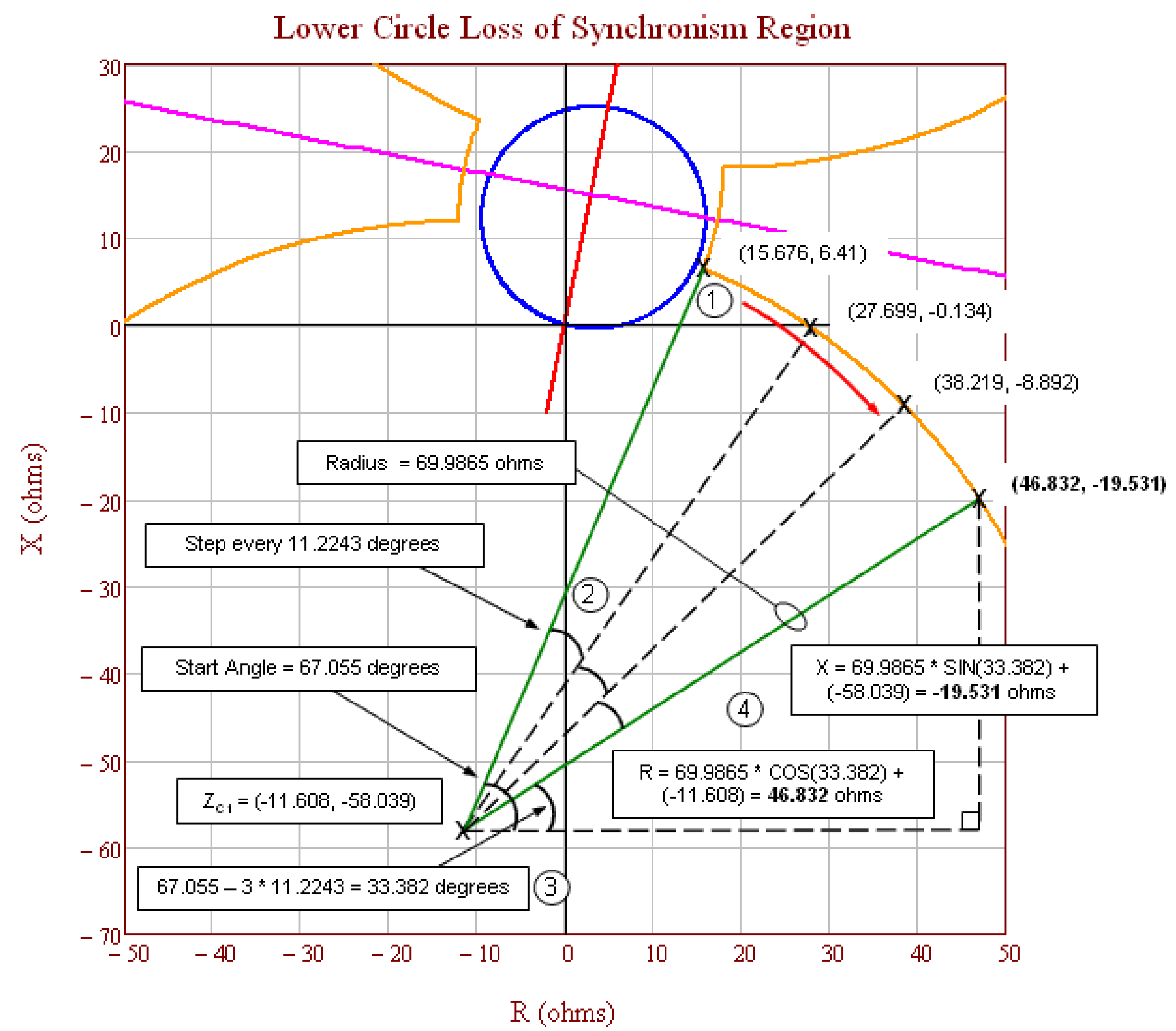


Figure 15d: Lower circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R–X coordinates.

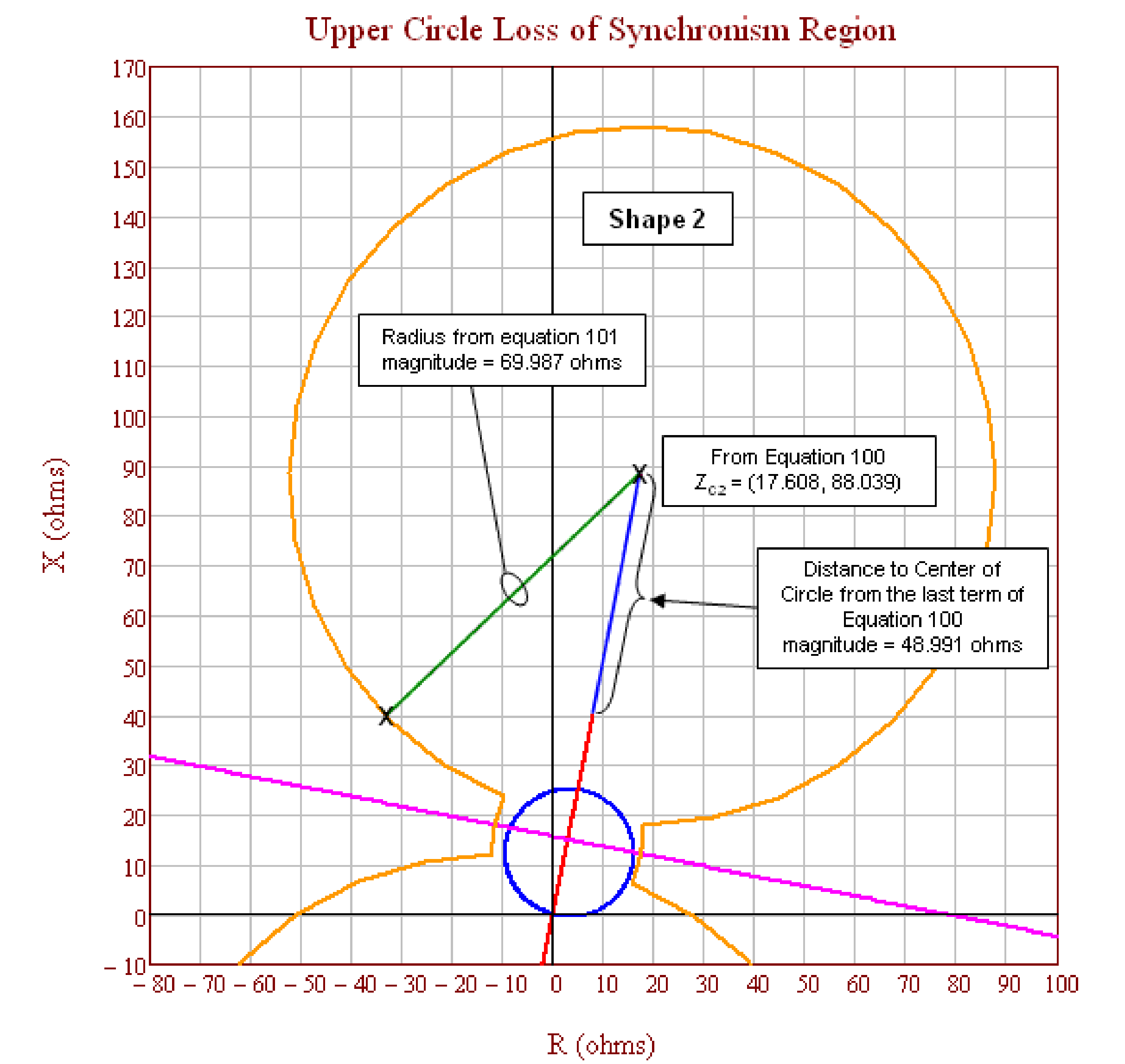


Figure 15e: Upper circle loss-of-synchronism region showing the coordinates of the circle center and the circle radius.

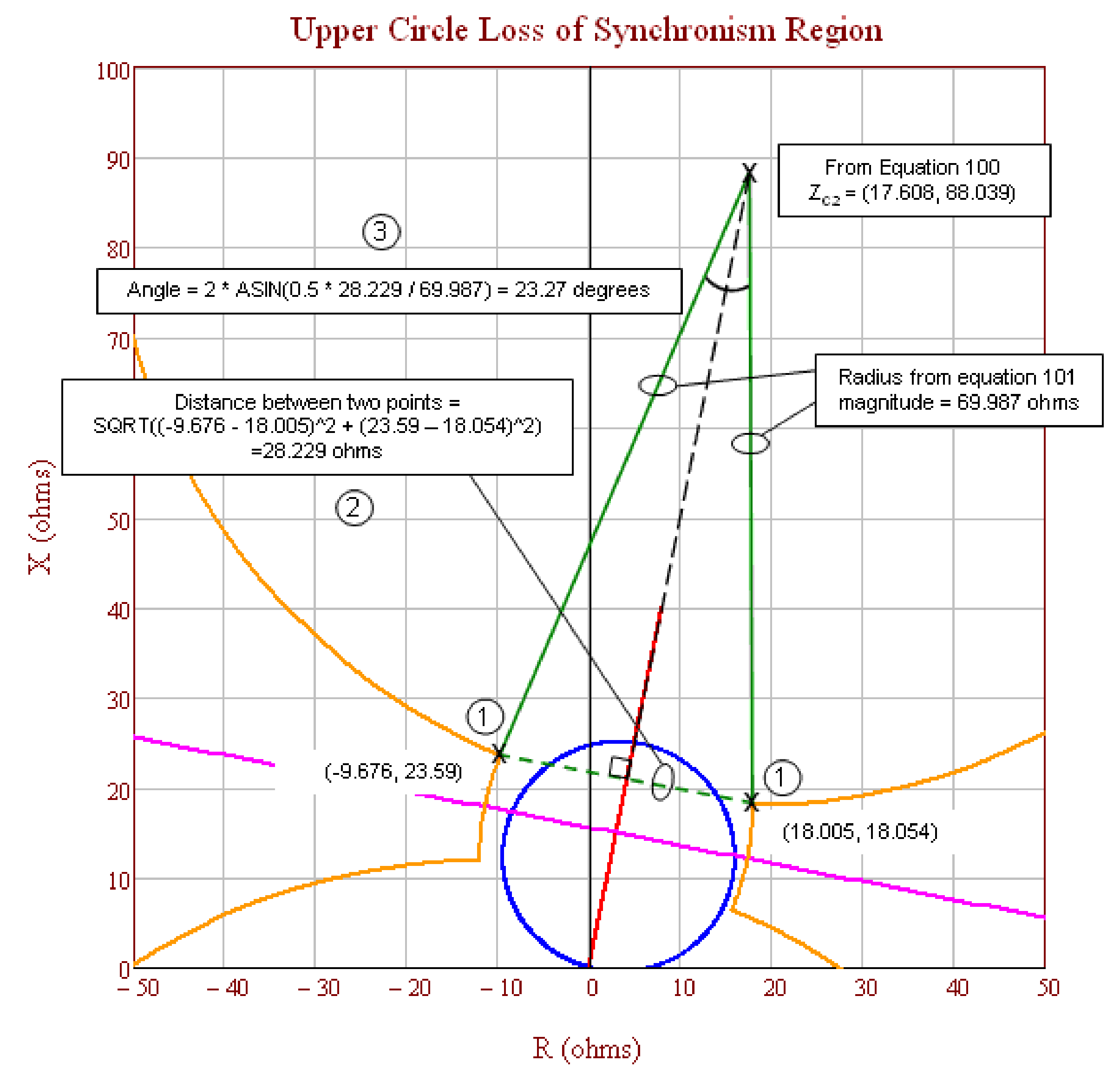


Figure 15f: Upper circle loss-of-synchronism region showing the first three steps to calculate the coordinates of the points on the circle. 1) Identify the upper circle points that intersect the lens shape where the sending-end to receiving-end voltage ratio is 1.43 (see lens shape calculations in Tables 2-7). 2) Calculate the distance between the two upper circle points identified in Step 1. 3) Calculate the angle of arc that connects the two upper circle points identified in Step 1.

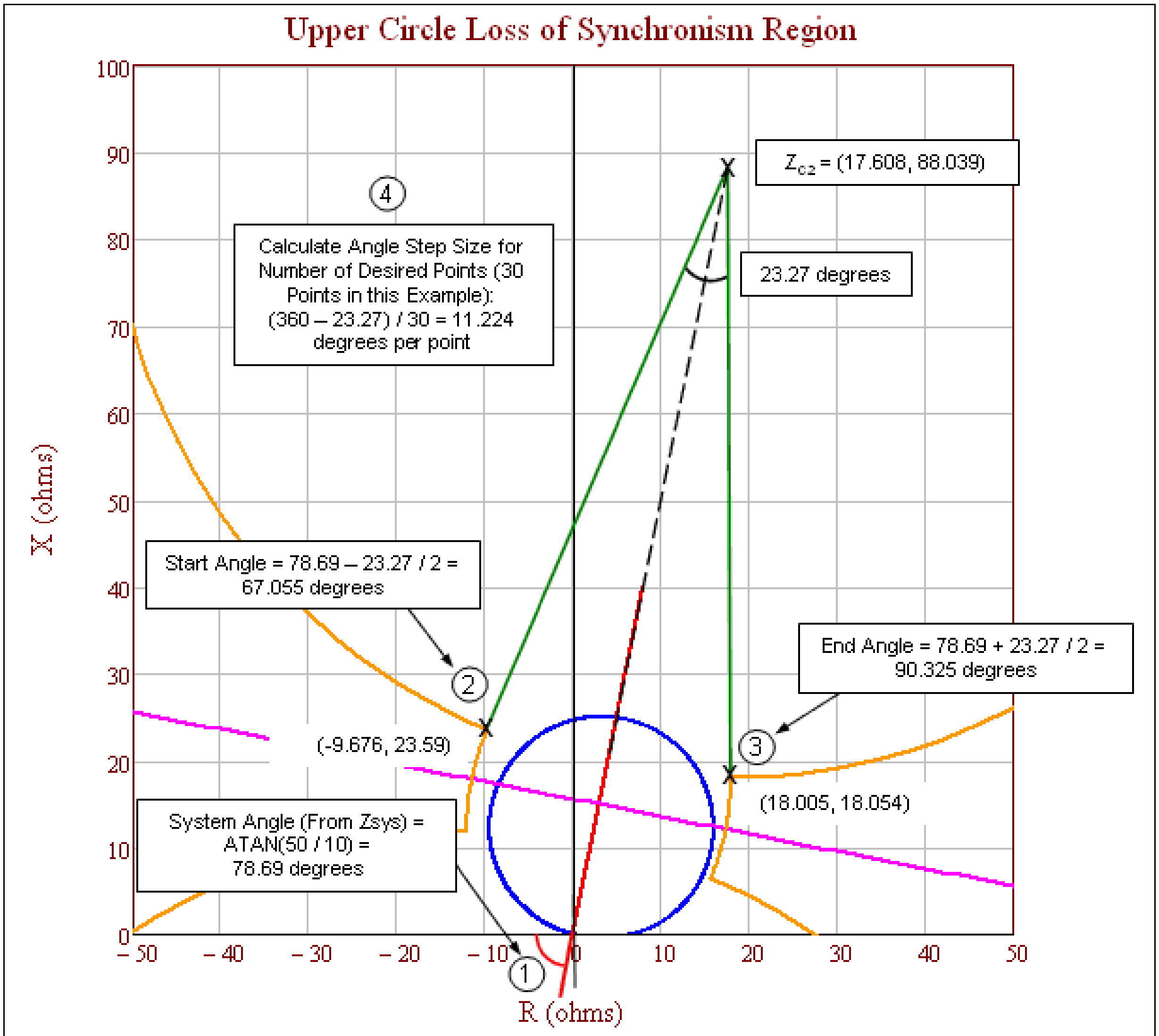


Figure 15g: Upper circle loss-of-synchronism region showing the steps to calculate the start angle, end angle, and the angle step size for the desired number of calculated points. 1) Calculate the system angle. 2) Calculate the start angle. 3) Calculate the end angle. 4) Calculate the angle step size for the desired number of points.

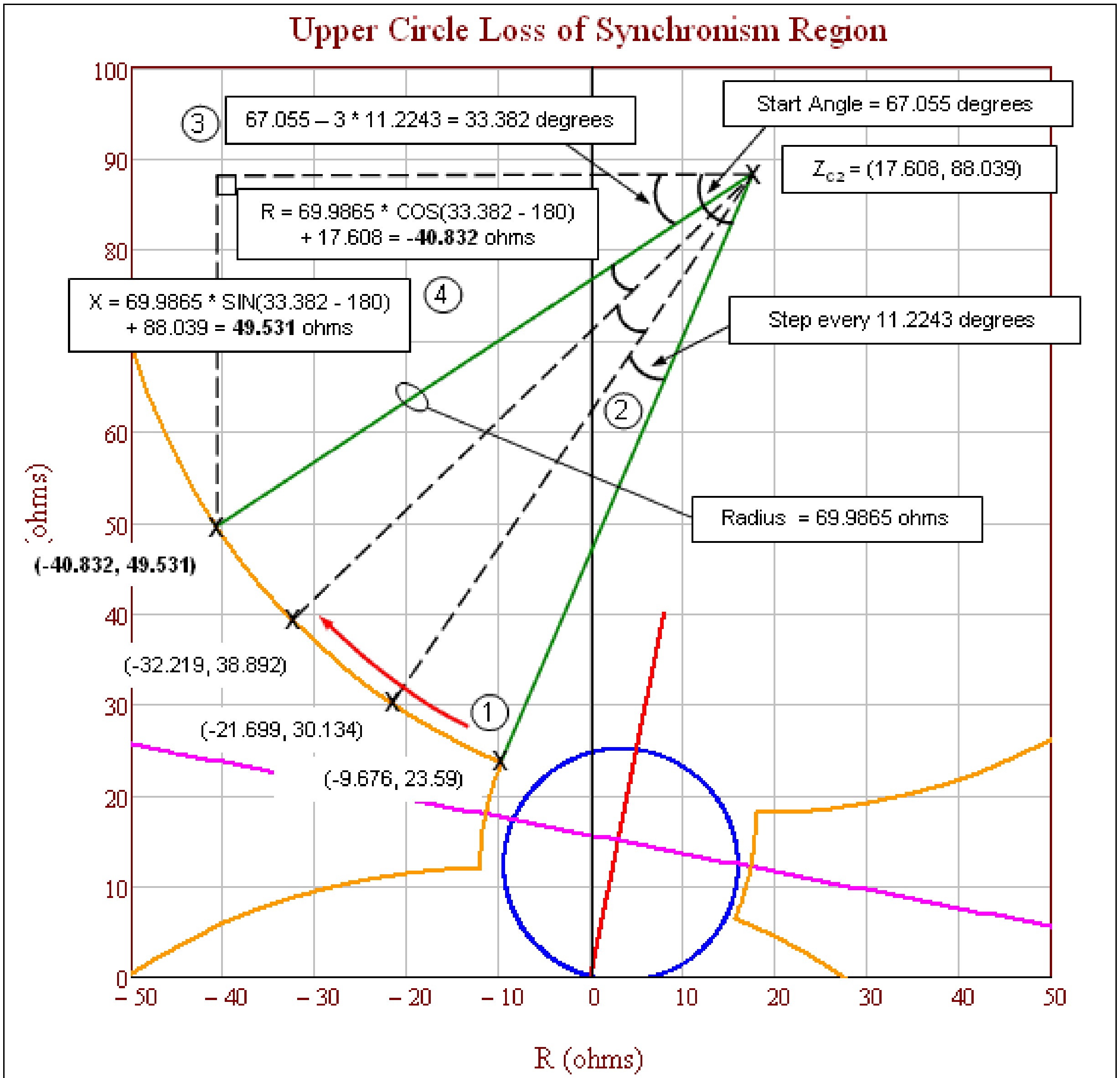


Figure 15h: Upper circle loss-of-synchronism region showing the final steps to calculate the coordinates of the points on the circle. 1) Start at the intersection with the lens shape and proceed in a clockwise direction. 2) Advance the step angle for each point. 3) Calculate the new angle after step advancement. 4) Calculate the R-X coordinates.

Lower Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	15.676	6.41
55.831	27.699	-0.134
44.606	38.219	-8.892
33.382	**46.832**	**-19.531**
22.158	53.21	-31.643
10.933	57.108	-44.765
359.709	58.378	-58.395
348.485	56.97	-72.011
337.26	52.939	-85.092
326.036	46.438	-97.139
314.812	37.717	-107.69
303.587	27.109	-116.341
292.363	15.02	-122.762
281.139	1.913	-126.707
269.914	-11.712	-128.026
258.69	-25.333	-126.667
247.466	-38.429	-122.682
236.241	-50.499	-116.225
225.017	-61.081	-107.542
213.793	-69.771	-96.965
202.568	-76.235	-84.899
191.344	-80.227	-71.806
180.12	-81.594	-58.185
168.895	-80.284	-44.56
157.671	-76.347	-31.45
146.447	-69.933	-19.357
135.222	-61.288	-8.744
123.998	-50.742	-0.016
112.774	-38.699	6.491
101.549	-25.62	10.53
90.325	-12.005	11.946

Upper Loss of Synchronism Circle Coordinates		
Angle (degrees)	R	+ jX
67.055	-9.676	23.59
55.831	-21.699	30.134
44.606	-32.219	38.892
33.382	**-40.832**	**49.531**
22.158	-47.21	61.643
10.933	-51.108	74.765
359.709	-52.378	88.395
348.485	-50.97	102.011
337.26	-46.939	115.092
326.036	-40.438	127.139
314.812	-31.717	137.69
303.587	-21.109	146.341
292.363	-9.02	152.762
281.139	4.087	156.707
269.914	17.712	158.026
258.69	31.333	156.667
247.466	44.429	152.682
236.241	56.499	146.225
225.017	67.081	137.542
213.793	75.771	126.965
202.568	82.235	114.899
191.344	86.227	101.806
180.12	87.594	88.185
168.895	86.284	74.56
157.671	82.347	61.45
146.447	75.933	49.357
135.222	67.288	38.744
123.998	56.742	30.016
112.774	44.699	23.509
101.549	31.62	19.47
90.325	18.005	18.054

Figure 15i: Full tables of calculated lower and upper loss-of-synchronism circle coordinates. The highlighted row is the detailed calculated points in Figures 15d and 15h.

Application Specific to Criterion B

The PRC-026-1 – Attachment B, Criterion B evaluates overcurrent elements used for tripping. The same criteria as PRC-026-1 – Attachment B, Criterion A is used except for an additional criterion (No. 4) that calculates a current magnitude based upon generator internal voltage of 1.05 per unit. A value of 1.05 per unit generator voltage is used to establish a minimum pickup current value for overcurrent relays that have a time delay less than 15 cycles. The sending-end and receiving-end voltages are established at 1.05 per unit at 120 degree system separation angle. The 1.05 per unit is the typical upper end of the operating voltage, which is also consistent with the maximum power transfer calculation using actual system source impedances in the PRC-023 NERC Reliability Standard. The formulas used to calculate the current are in Table 14 below.

Table 14: Example Calculation (Overcurrent)			
This example is for a 230 kV line terminal with a directional instantaneous phase overcurrent element set to 50 amps secondary times a CT ratio of 160:1 that equals 8,000 amps, primary. The following calculation is where V_S equals the base line-to-ground sending-end generator source voltage times 1.05 at an angle of 120 degrees, V_R equals the base line-to-ground receiving-end generator internal voltage times 1.05 at an angle of 0 degrees, and Z_{sys} equals the sum of the sending-end source, line, and receiving-end source impedances in ohms. Here, the instantaneous phase setting of 8,000 amps is greater than the calculated system current of 5,716 amps; therefore, it meets PRC-026-1 – Attachment B, Criterion B.			
Eq. (102)	$V_S = \frac{V_{LL}\angle 120°}{\sqrt{3}} \times 1.05$		
	$V_S = \frac{230{,}000\angle 120°\ V}{\sqrt{3}} \times 1.05$		
	$V_S = 139{,}430\angle 120°\ V$		
Receiving-end generator terminal voltage.			
Eq. (103)	$V_R = \frac{V_{LL}\angle 0°}{\sqrt{3}} \times 1.05$		
	$V_R = \frac{230{,}000\angle 0°\ V}{\sqrt{3}} \times 1.05$		
	$V_R = 139{,}430\angle 0°\ V$		
The total impedance of the system (Z_{sys}) equals the sum of the sending-end source impedance (Z_S), the impedance of the line (Z_L), and receiving-end impedance (Z_R) in ohms.			
Given:	$Z_S = 3 + j26\ \Omega$	$Z_L = 1.3 + j8.7\ \Omega$	$Z_R = 0.3 + j7.3\ \Omega$
Eq. (104)	$Z_{sys} = Z_S + Z_L + Z_R$		
	$Z_{sys} = (3 + j26)\ \Omega + (1.3 + j8.7)\ \Omega + (0.3 + j7.3)\ \Omega$		
	$Z_{sys} = 4.6 + j42\ \Omega$		
Total system current.			
Eq. (105)	$I_{sys} = \frac{(V_S - V_R)}{Z_{sys}}$		
	$I_{sys} = \frac{(139{,}430\angle 120°\ V - 139{,}430\angle 0°\ V)}{(4.6 + j42)\ \Omega}$		
	$I_{sys} = 5{,}715.82\angle 66.25°\ A$		

Application Specific to Three-Terminal Lines

If a three-terminal line is identified as an Element that is susceptible to a power swing based on Requirement R1, the load-responsive protective relays at each end of the three-terminal line must be evaluated.

As shown in Figure 15j, the source impedances at each end of the line can be obtained from the similar short circuit calculation as for the two-terminal line (assuming the parallel transfer impedances are ignored).

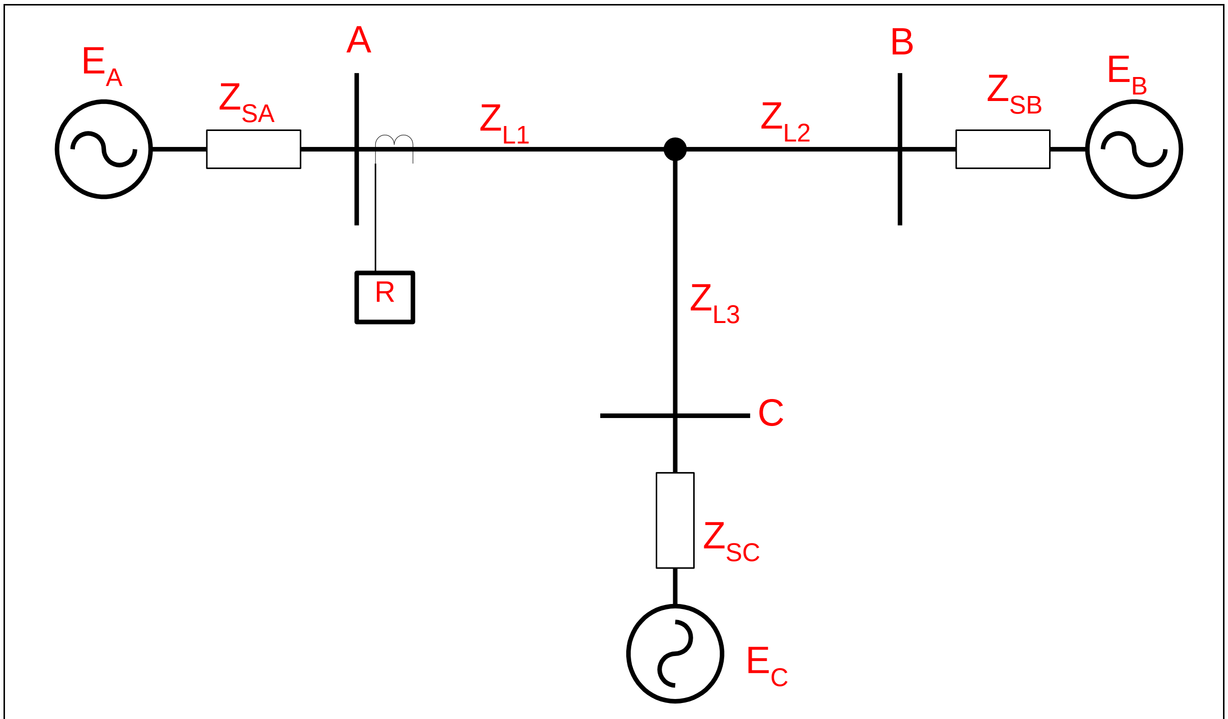


Figure 15j: Three-terminal line. To evaluate the load-responsive protective relays on the three-terminal line at Terminal A, the circuit in Figure 15j is first reduced to the equivalent circuit shown in Figure 15k. The evaluation process for the load-responsive protective relays on the line at Terminal A will now be the same as that of the two-terminal line.

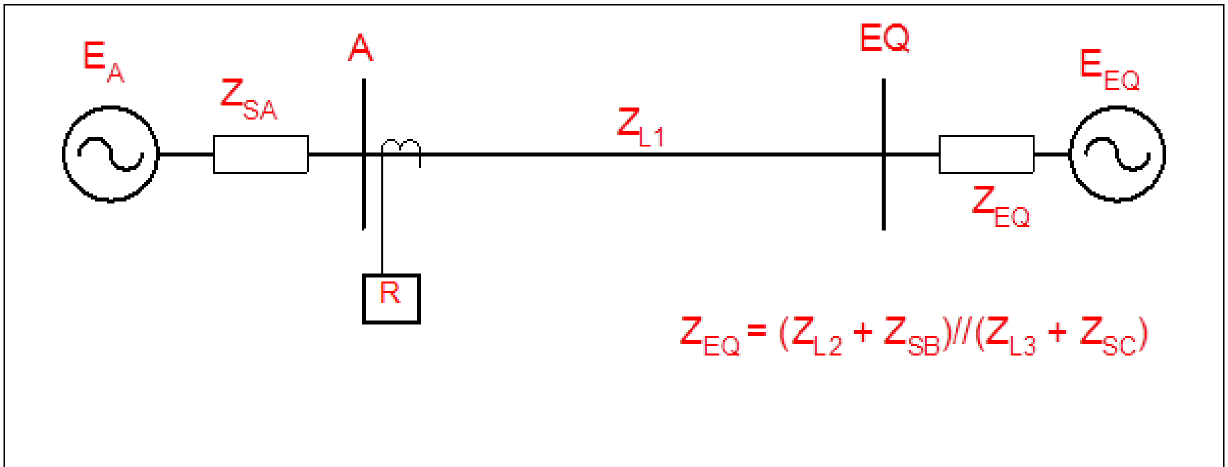


Figure 15k: Three-terminal line reduced to a two-terminal line.

Application to Generation Elements

As with transmission BES Elements, the determination of the apparent impedance seen at an Element located at, or near, a generation Facility is complex for power swings due to various interdependent quantities. These variances in quantities are caused by changes in machine internal voltage, speed governor action, voltage regulator action, the reaction of other local generators, and the reaction of other interconnected transmission BES Elements as the event progresses through the time domain. Though transient stability simulations may be used to determine the apparent impedance for verifying load-responsive relay settings,[19,20] Requirement R2, PRC-026-1 – Attachment B, Criteria A and B provides a simplified method for evaluating the load-responsive protective relay's susceptibility to tripping in response to a stable power swing without requiring stability simulations.

In general, the electrical center will be in the transmission system for cases where the generator is connected through a weak transmission system (high external impedance). In other cases where the generator is connected through a strong transmission system, the electrical center could be inside the unit connected zone.[21] In either case, load-responsive protective relays connected at the generator terminals or at the high-voltage side of the generator step-up (GSU) transformer may be challenged by power swings. Relays that may be challenged by power swings will be determined by the Planning Coordinator in Requirement R1 or by the Generator Owner after becoming aware of a generator, transformer, or transmission line BES Element that tripped[22] in response to a stable or unstable power swing due to the operation of its protective relay(s) in Requirement R2.

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[19] Donald Reimert, *Protective Relaying for Power Generation Systems*, Boca Raton, FL, CRC Press, 2006.

[20] Prabha Kundur, *Power System Stability and Control*, EPRI, McGraw Hill, Inc., 1994.

[21] Ibid, Kundur.

[22] See Guidelines and Technical Basis section, "Becoming Aware of an Element That Tripped in Response to a Power Swing,"

Voltage controlled time-overcurrent and voltage-restrained time-overcurrent relays are excluded from this standard. When these relays are set based on equipment permissible overload capability, their operating times are much greater than 15 cycles for the current levels observed during a power swing.

Instantaneous overcurrent, time-overcurrent, and definite-time overcurrent relays with a time delay of less than 15 cycles for the current levels observed during a power swing are applicable and are required to be evaluated for identified Elements.

The generator loss-of-field protective function is provided by impedance relay(s) connected at the generator terminals. The settings are applied to protect the generator from a partial or complete loss of excitation under all generator loading conditions and, at the same time, be immune to tripping on stable power swings. It is more likely that the loss-of-field relay would operate during a power swing when the automatic voltage regulator (AVR) is in manual mode rather than when in automatic mode.[23] Figure 16 illustrates the loss-of-field relay in the R-X plot, which typically includes up to three zones of protection.

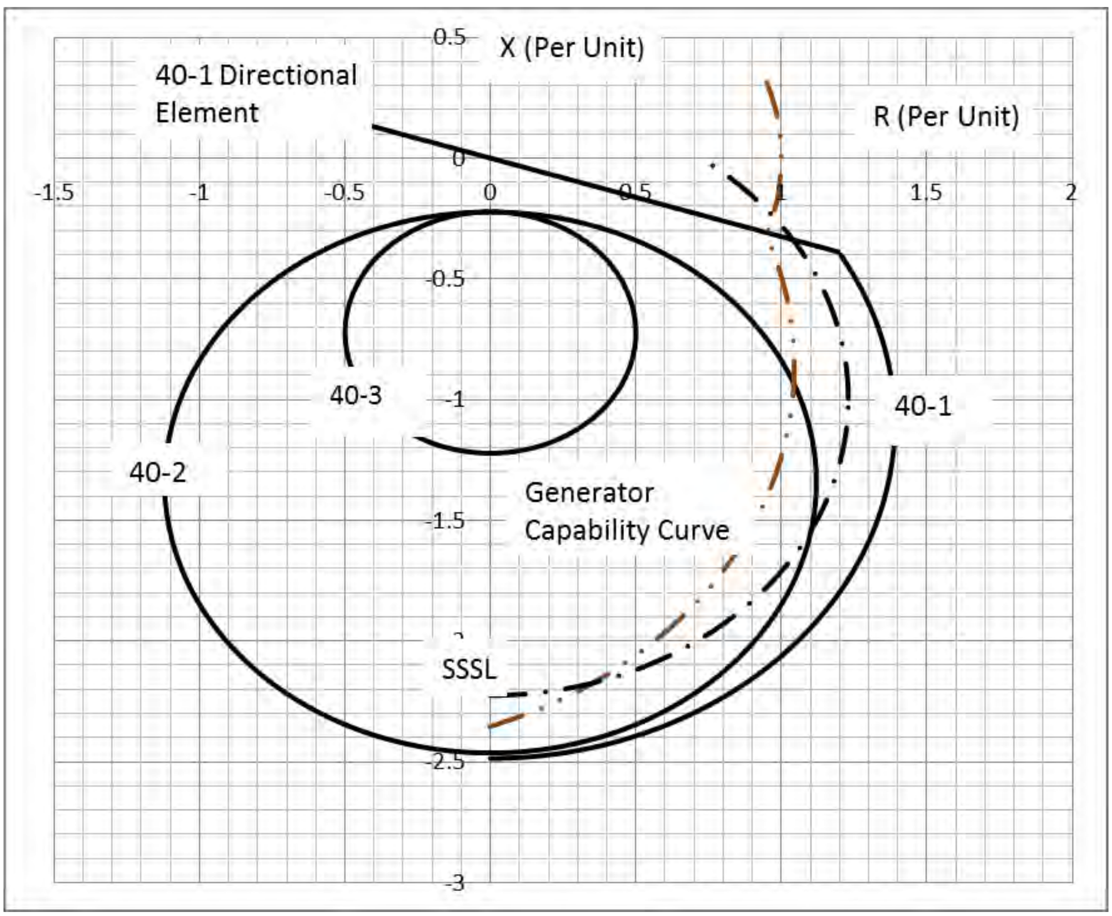

Figure 16: An R-X graph of typical impedance settings for loss-of-field relays.

[23] John Burdy, *Loss-of-excitation Protection for Synchronous Generators GER-3183*, General Electric Company.

Loss-of-field characteristic 40-1 has a wider impedance characteristic (positive offset) than characteristic 40-2 or characteristic 40-3 and provides additional generator protection for a partial loss of field or a loss of field under low load (less than 10% of rated). The tripping logic of this protection scheme is established by a directional contact, a voltage setpoint, and a time delay. The voltage and time delay add security to the relay operation for stable power swings. Characteristic 40-3 is less sensitive to power swings than characteristic 40-2 and is set outside the generator capability curve in the leading direction. Regardless of the relay impedance setting, PRC-019[24] requires that the "in-service limiters operate before Protection Systems to avoid unnecessary trip" and "in-service Protection System devices are set to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits." Time delays for tripping associated with loss-of-field relays[25,26] have a range from 15 cycles for characteristic 40-2 to 60 cycles for characteristic 40-1 to minimize tripping during stable power swings. In PRC-026-1, 15 cycles establishes a threshold for applicability; however, it is the responsibility of the Generator Owner to establish settings that provide security against stable power swings and, at the same time, dependable protection for the generator.

The simple two-machine system circuit (method also used in the Application to Transmission Elements section) is used to analyze the effect of a power swing at a generator facility for load-responsive relays. In this section, the calculation method is used for calculating the impedance seen by the relay connected at a point in the circuit.[27] The electrical quantities used to determine the apparent impedance plot using this method are generator saturated transient reactance (X'_d), GSU transformer impedance (X_{GSU}), transmission line impedance (Z_L), and the system equivalent (Z_e) at the point of interconnection. All impedance values are known to the Generator Owner except for the system equivalent. The system equivalent is obtainable from the Transmission Owner. The sending-end and receiving-end source voltages are varied from 0.0 to 1.0 per unit to form the lens shape portion of the unstable power swing region. The voltage range of 0.7 to 1.0 results in a ratio range from 0.7 to 1.43. This ratio range is used to form the lower and upper loss-of-synchronism circle shapes of the unstable power swing region. A system separation angle of 120 degrees is used in accordance with PRC-026-1 – Attachment B criteria for each load-responsive protective relay evaluation.

Table 15 below is an example calculation of the apparent impedance locus method based on Figures 17 and 18.[28] In this example, the generator is connected to the 345 kV transmission system through the GSU transformer and has the listed ratings. Note that the load-responsive protective relays in this example may have ownership with the Generator Owner or the Transmission Owner.

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[24] Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

[25] Ibid, Burdy.

[26] *Applied Protective Relaying*, Westinghouse Electric Corporation, 1979.

[27] Edward Wilson Kimbark, *Power System Stability, Volume II: Power Circuit Breakers and Protective Relays*, Published by John Wiley and Sons, 1950.

[28] Ibid, Kimbark.

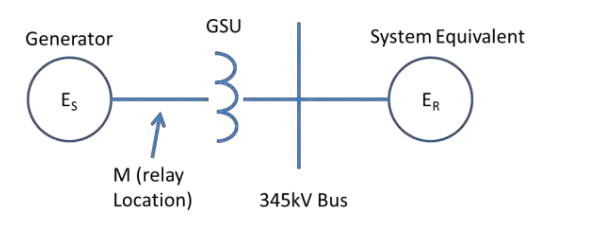

Figure 17: Simple one-line diagram of the system to be evaluated.

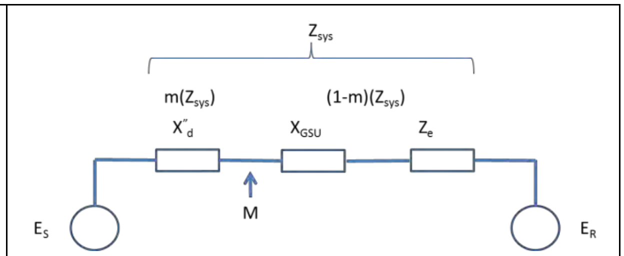

Figure 18: Simple system equivalent impedance diagram to be evaluated.[29]

Table15: Example Data (Generator)	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA)	940 MVA
Saturated transient reactance (940 MVA base)	$X'_d = 0.3845$ per unit
Generator rated voltage (Line-to-Line)	$20\ kV$
Generator step-up (GSU) transformer rating	$880\ MVA$
GSU transformer reactance (880 MVA base)	$\mathrm{X_{GSU}} = 16.05\%$
System Equivalent (100 MVA base)	$Z_e = 0.00723\angle 90°$ per unit
Generator Owner Load-Responsive Protective Relays	
40-1	Positive Offset Impedance
	Offset = 0.294 per unit
	Diameter = 0.294 per unit
40-2	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 2.24 per unit
40-3	Negative Offset Impedance
	Offset = 0.22 per unit
	Diameter = 1.00 per unit
21-1	Diameter = 0.643 per unit
	MTA = 85°

[29] Ibid, Kimbark.

Table15: Example Data (Generator)	
50	I (pickup) = 5.0 per unit
Transmission Owned Load-Responsive Protective Relays	
21-2	Diameter = 0.55 per unit
	MTA = 85°

Calculations shown for a 120 degree angle and $E_S/E_R = 1$. The equation for calculating Z_R is:[30]

Eq. (106) $$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$$

Where m is the relay location as a function of the total impedance (real number less than 1)

E_S and E_R is the sending-end and receiving-end voltages

Z_{sys} is the total system impedance

Z_R is the complex impedance at the relay location and plotted on an R-X diagram

All of the above are constants (940 MVA base) while the angle δ is varied. Table 16 below contains calculations for a generator using the data listed in Table 15.

Table16: Example Calculations (Generator)			
The following calculations are on a 940 MVA base.			
Given:	$X'_d = j0.3845\,pu$	$X_{GSU} = j0.17144\,pu$	$Z_e = j0.06796\,pu$
Eq. (107)	$Z_{sys} = X'_d + X_{GSU} + Z_e$		
	$Z_{sys} = j0.3845\,pu + j0.17144\,pu + j0.06796\,pu$		
	$Z_{sys} = 0.6239\angle 90°\,pu$		
Eq. (108)	$m = \frac{X'_d}{Z_{sys}} = \frac{0.3845}{0.6239} = 0.6163$		
Eq. (109)	$Z_R = \left(\frac{(1-m)(E_S\angle\delta) + (m)(E_R)}{E_S\angle\delta - E_R}\right) \times Z_{sys}$		
	$Z_R = \left(\frac{(1-0.6163)\times(1\angle 120°) + (0.6163)(1\angle 0°)}{1\angle 120° - 1\angle 0°}\right) \times (0.6239\angle 90°)\,pu$		

[30] Ibid, Kimbark.

Table16: Example Calculations (Generator)	
	$Z_R = \left(\frac{0.4244 + j0.3323}{-1.5 + j\,0.866}\right) \times (0.6239\angle 90°)\;pu$
	$Z_R = (0.3116\angle -111.95°) \times (0.6239\angle 90°)\;pu$
	$Z_R = 0.194\angle -21.95°\;pu$
	$Z_R = -0.18 - j0.073\;pu$

Table 17 lists the swing impedance values at other angles and at E_S/E_R = 1, 1.43, and 0.7. The impedance values are plotted on an R-X graph with the center being at the generator terminals for use in evaluating impedance relay settings.

Table 17: Sample Calculations for a Swing Impedance Chart for Varying Voltages at the Sending-End and Receiving-End.

	E_S/E_R=1		E_S/E_R=1.43		E_S/E_R=0.7	
	Z_R		Z_R		Z_R	
Angle (δ) (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)	Magnitude (pu)	Angle (Degrees)
90	0.320	-13.1	0.296	6.3	0.344	-31.5
120	0.194	-21.9	0.173	-0.4	0.227	-40.1
150	0.111	-41.0	0.082	-10.3	0.154	-58.4
210	0.111	-25.9	0.082	190.3	0.154	238.4
240	0.194	201.9	0.173	180.4	0.225	220.1
270	0.320	193.1	0.296	173.7	0.344	211.5

Requirement R2 Generator Examples

Distance Relay Application

Based on PRC-026-1 – Attachment B, Criterion A, the distance relay (21-1) (i.e., owned by the Generation Owner) characteristic is in the region where a stable power swing would not occur as shown in Figure 19. There is no further obligation to the owner in this standard for this load-responsive protective relay.

The distance relay (21-2) (i.e., owned by the Transmission Owner) is connected at the high-voltage side of the GSU transformer and its impedance characteristic is in the region where a stable power swing could occur causing the relay to operate. In this example, if the intentional time delay of this relay is less than 15 cycles, the PRC-026 – Attachment B, Criterion A cannot be met, thus the Transmission Owner is required to create a CAP (Requirement R3). Some of the options include, but are not limited to, changing the relay setting (i.e., impedance reach, angle, time delay), modify the scheme (i.e., add PSB), or replace the Protection System. Note that the relay may be excluded from this standard if it has an intentional time delay equal to or greater than 15 cycles.

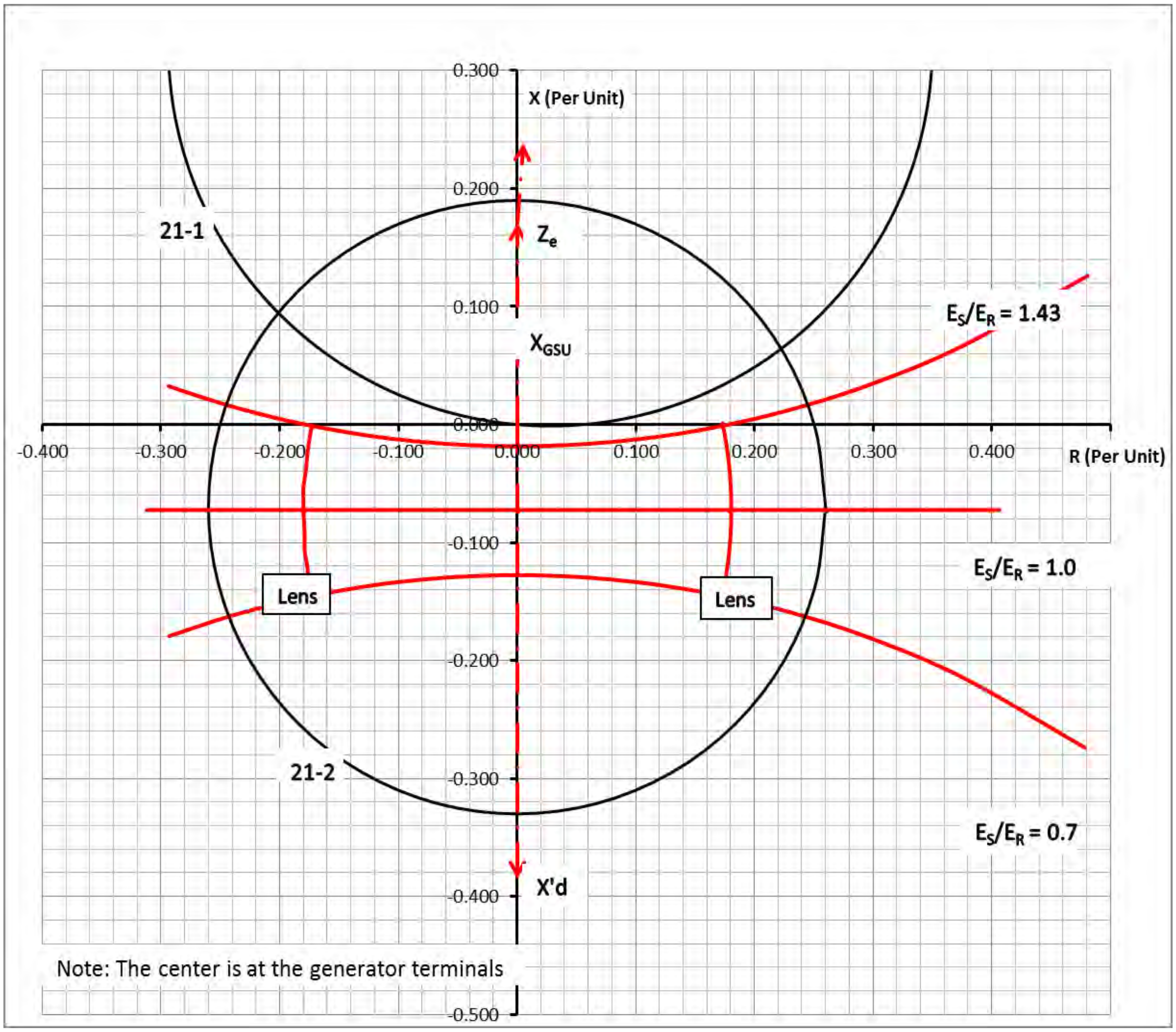

Figure 19: Swing impedance graph for impedance relays at a generating facility.

Loss-of-Field Relay Application

In Figure 20, the R-X diagram shows the loss-of-field relay (40-1 and 40-2) characteristics are in the region where a stable power swing can cause a relay operation. Protective relay 40-1 would be excluded if it has an intentional time delay equal to or greater than 15 cycles. Similarly, 40-2 would be excluded if its intentional time delay is equal to or greater than 15 cycles. For example, if 40-1 has a time delay of 1 second and 40-2 has a time delay of 0.25 seconds, they are excluded and there is no further obligation on the Generator Owner in this standard for these relays. The loss-of-field relay characteristic 40-3 is entirely inside the unstable power swing region. In this case, the owner may select high speed tripping on operation of the 40-3 impedance element.

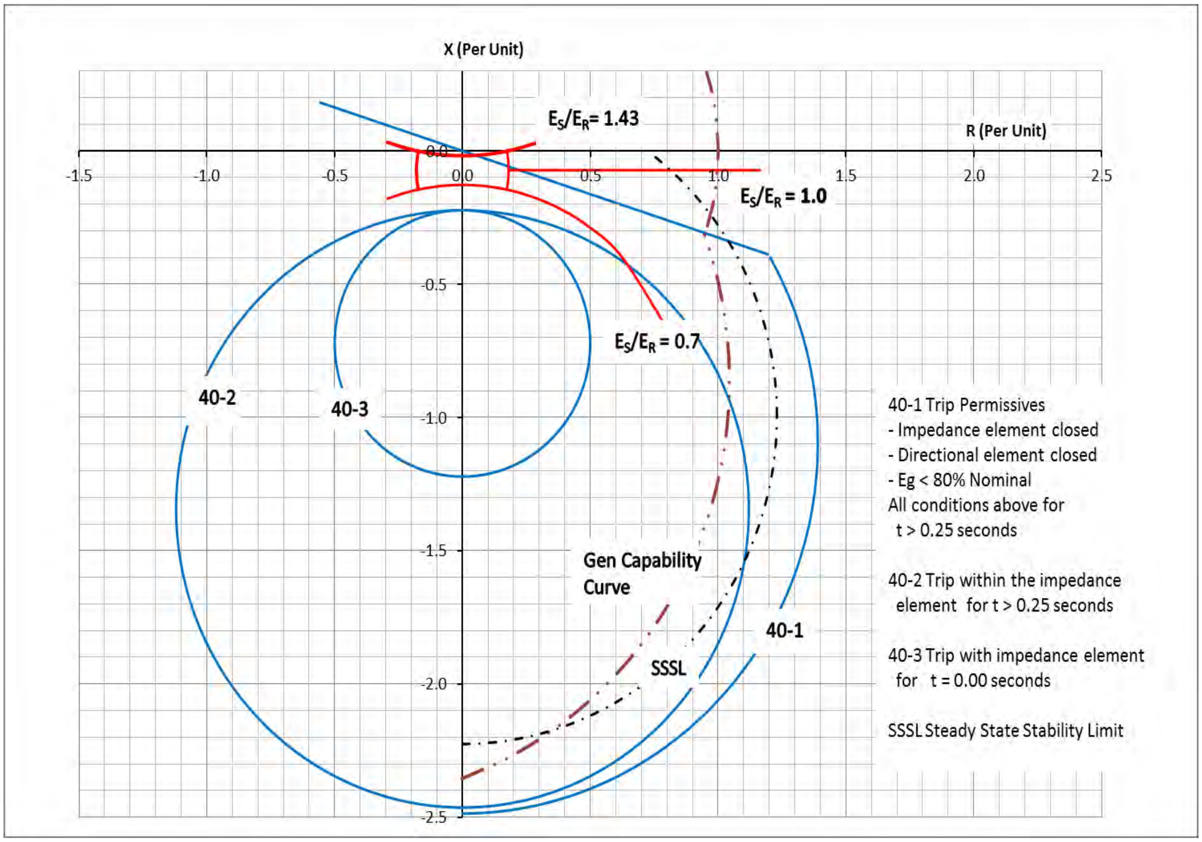

Figure 20: Typical R-X graph for loss-of-field relays with a portion of the unstable power swing region defined by PRC-026-1 – Attachment B, Criterion A.

Instantaneous Overcurrent Relay

In similar fashion to the transmission line overcurrent example calculation in Table 14, the instantaneous overcurrent relay minimum setting is established by PRC-026-1 – Attachment B, Criterion B. The solution is found by:

Eq. (110) $$I_{sys} = \frac{E_S - E_R}{Z_{\text{sys}}}$$

As stated in the relay settings in Table 15, the relay is installed on the high-voltage side of the GSU transformer with a pickup of 5.0 per unit. The maximum allowable current is calculated below.

$$I_{sys} = \frac{(1.05\angle 120° - 1.05\angle 0°)}{0.6239\angle 90°}\ pu$$

$$I_{sys} = \frac{1.819\angle 150°}{0.6239\angle 90°}\, pu$$

$$I_{sys} = 2.91\ \angle 60°\, pu$$

The instantaneous phase setting of 5.0 per unit is greater than the calculated system current of 2.91 per unit; therefore, it meets the PRC-026-1 – Attachment B, Criterion B.

Out-of-Step Tripping for Generation Facilities

Out-of-step protection for the generator generally falls into three different schemes. The first scheme is a distance relay connected at the high-voltage side of the GSU transformer with the directional element looking toward the generator. Because this relay setting may be the same setting used for generator backup protection (see Requirement R2 Generator Examples, Distance Relay Application), it is susceptible to tripping in response to stable power swings and would require modification. Because this scheme is susceptible to tripping in response to stable power swings and any modification to the mho circle will jeopardize the overall protection of the out-of-step protection of the generator, available technical literature does not recommend using this scheme specifically for generator out-of-step protection. The second and third out-of-step Protection System schemes are commonly referred to as single and double blinder schemes. These schemes are installed or enabled for out-of-step protection using a combination of blinders, a mho element, and timers. The combination of these protective relay functions provides out-of-step protection and discrimination logic for stable and unstable power swings. Single blinder schemes use logic that discriminate between stable and unstable power swings by issuing a trip command after the first slip cycle. Double blinder schemes are more complex than the single blinder scheme and, depending on the settings of the inner blinder, a trip for a stable power swing may occur. While the logic discriminates between stable and unstable power swings in either scheme, it is important that the trip initiating blinders be set at an angle greater than the stability limit of 120 degrees to remove the possibility of a trip for a stable power swing. Below is a discussion of the double blinder scheme.

Double Blinder Scheme

The double blinder scheme is a method for measuring the rate of change of positive sequence impedance for out-of-step swing detection. The scheme compares a timer setting to the actual elapsed time required by the impedance locus to pass between two impedance characteristics. In this case, the two impedance characteristics are simple blinders, each set to a specific resistive reach on the R-X plane. Typically, the two blinders on the left half plane are the mirror images of those on the right half plane. The scheme typically includes a mho characteristic which acts as a starting element, but is not a tripping element.

The scheme detects the blinder crossings and time delays as represented on the R-X plane as shown in Figure 21. The system impedance is composed of the generator transient (X_d'), GSU transformer (X_T), and transmission system (X_{system}), impedances.

The scheme logic is initiated when the swing locus crosses the outer Blinder R1 (Figure 21), on the right at separation angle α. The scheme only commits to take action when a swing crosses the inner blinder. At this point the scheme logic seals in the out-of-step trip logic at separation angle β. Tripping actually asserts as the impedance locus leaves the scheme characteristic at separation angle δ.

The power swing may leave both inner and outer blinders in either direction, and tripping will assert. Therefore, the inner blinder must be set such that the separation angle β is large enough that the system cannot recover. This angle should be set at 120 degrees or more. Setting the angle greater than 120 degrees satisfies the PRC-026-1 – Attachment B, Criterion A (No. 1, 1st bullet) since the tripping function is asserted by the blinder element. Transient stability studies may indicate that a smaller stability limit angle is acceptable under PRC-026-1 – Attachment B, Criterion A (No. 1, 2nd bullet). In this respect, the double blinder scheme is similar to the double lens and triple lens schemes and many transmission application out-of-step schemes.

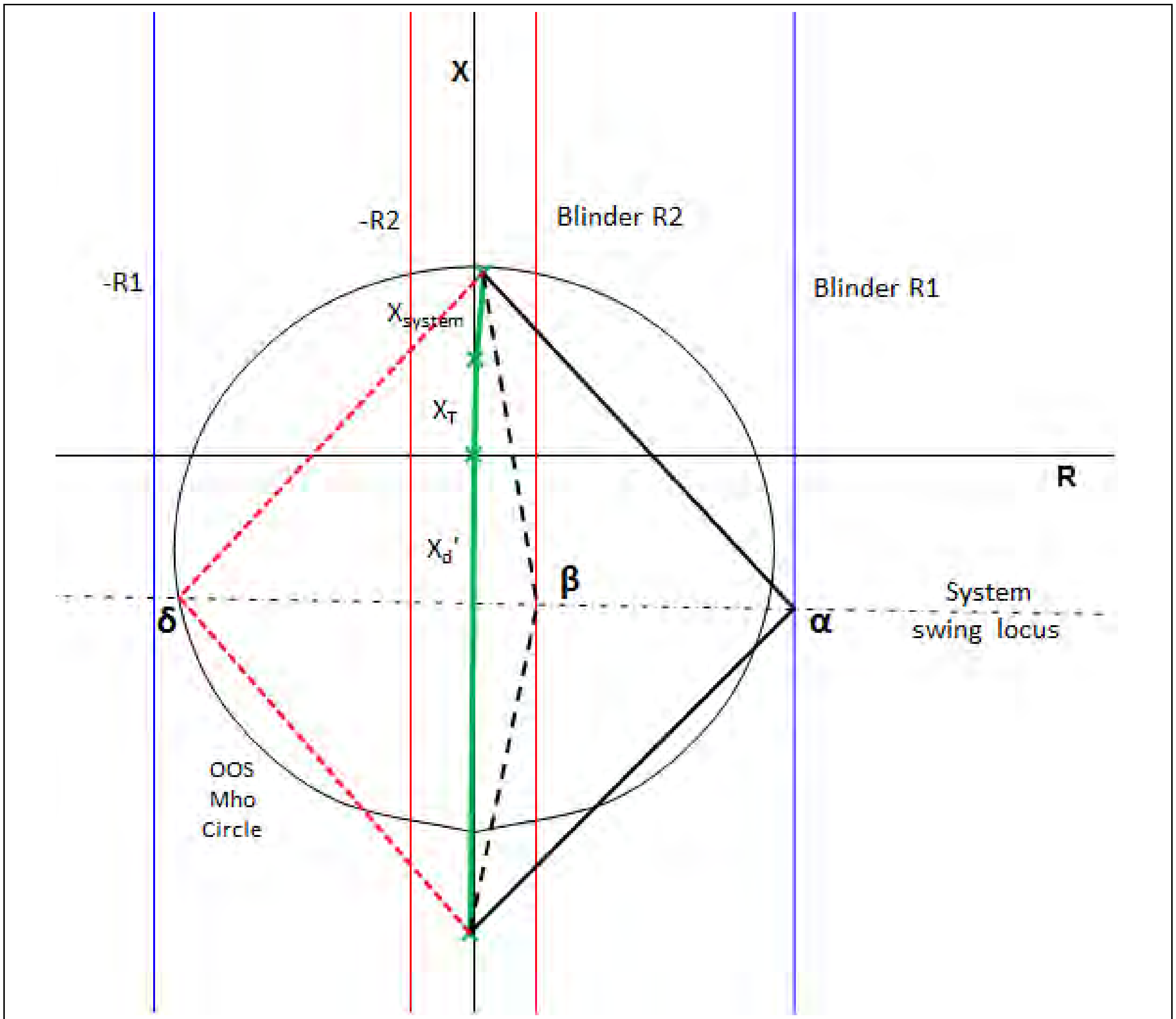

Figure 21: Double Blinder Scheme generic out of step characteristics.

Figure 22 illustrates a sample setting of the double blinder scheme for the example 940 MVA generator. The only setting requirement for this relay scheme is the right inner blinder, which must be set greater than the separation angle of 120 degrees (or a lesser angle based on a transient stability study) to ensure that the out-of-step protective function is expected to not trip in response to a stable power swing during non-Fault conditions. Other settings such as the mho characteristic, outer blinders, and timers are set according to transient stability studies and are not a part of this standard.

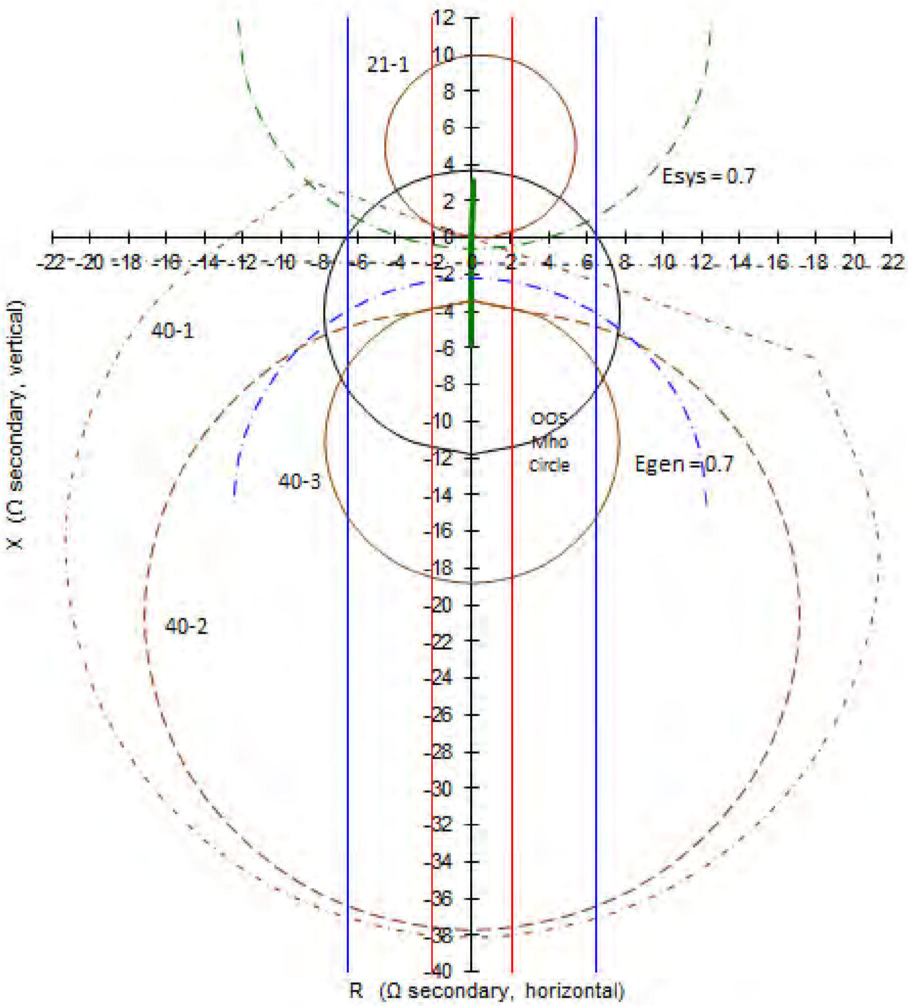

Figure 22: Double Blinder Out-of-Step Scheme with unit impedance data and load-responsive protective relay impedance characteristics for the example 940 MVA generator, scaled in relay secondary ohms.

Requirement R3

To achieve the stated purpose of this standard, which is to ensure that relays are expected to not trip in response to stable power swings during non-Fault conditions, this Requirement ensures that the applicable entity develops a Corrective Action Plan (CAP) that reduces the risk of relays tripping in response to a stable power swing during non-Fault conditions that may occur on any applicable BES Element.

Requirement R4

To achieve the stated purpose of this standard, which is to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions, the applicable entity is required to implement any CAP developed pursuant to Requirement R3 such that the Protection System will meet PRC-026-1 – Attachment B criteria or can be excluded under the PRC-026-1 – Attachment A criteria (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the BES Element). Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until all actions are complete. Accomplishing this objective is intended to reduce the occurrence of Protection System tripping during a stable power swing, thereby improving reliability and minimizing risk to the BES.

The following are examples of actions taken to complete CAPs for a relay that did not meet PRC-026-1 – Attachment B and could be at-risk of tripping in response to a stable power swing during non-Fault conditions. A Protection System change was determined to be acceptable (without diminishing the ability of the relay to protect for faults within its zone of protection).

> **Example R4a:** Actions: Settings were issued on 6/02/2015 to reduce the Zone 2 reach of the impedance relay used in the directional comparison unblocking (DCUB) scheme from 30 ohms to 25 ohms so that the relay characteristic is completely contained within the lens characteristic identified by the criterion. The settings were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

> **Example R4b:** Actions: Settings were issued on 6/02/2015 to enable out-of-step blocking on the existing microprocessor-based relay to prevent tripping in response to stable power swings. The setting changes were applied to the relay on 6/25/2015. CAP was completed on 06/25/2015.

The following is an example of actions taken to complete a CAP for a relay responding to a stable power swing that required the addition of an electromechanical power swing blocking relay.

> **Example R4c:** Actions: A project for the addition of an electromechanical power swing blocking relay to supervise the Zone 2 impedance relay was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The relay installation was completed on 9/25/2015. CAP was completed on 9/25/2015.

The following is an example of actions taken to complete a CAP with a timetable that required updating for the replacement of the relay.

> **Example R4d:** Actions: A project for the replacement of the impedance relays at both terminals of line X with line current differential relays was initiated on 6/5/2015 to prevent tripping in response to stable power swings. The completion of the project was postponed due to line outage rescheduling from 11/15/2015 to 3/15/2016. Following the timetable change, the impedance relay replacement was completed on 3/18/2016. CAP was completed on 3/18/2016.

The CAP is complete when all the documented actions to remedy the specific problem (i.e., unnecessary tripping during stable power swings) are completed.

Justification for Including Unstable Power Swings in the Requirements

Protection Systems that are applicable to the Standard and must be secure for a stable power swing condition (i.e., meets PRC-026-1 – Attachment B criteria) are identified based on Elements that are susceptible to both stable and unstable power swings. This section provides an example of why Elements that trip in response to unstable power swings (in addition to stable power swings) are identified and that their load-responsive protective relays need to be evaluated under PRC-026-1 – Attachment B criteria.

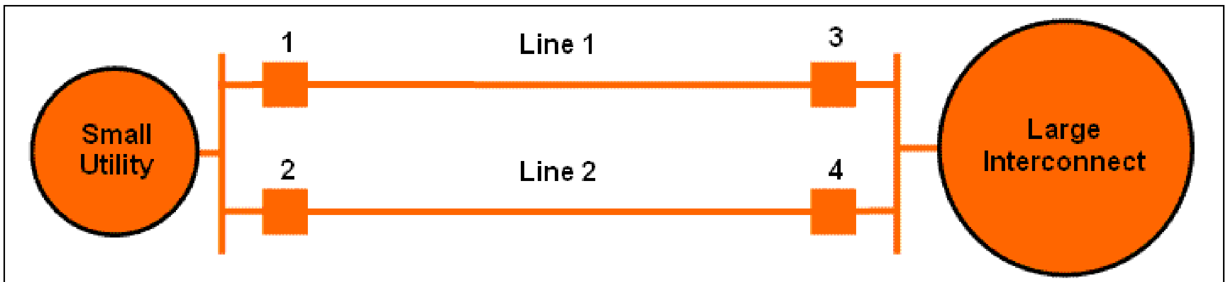

Figure 23: A simple electrical system where two lines tie a small utility to a much larger interconnection.

In Figure 23 the relays at circuit breakers 1, 2, 3, and 4 are equipped with a typical overreaching Zone 2 pilot system, using a Directional Comparison Blocking (DCB) scheme. Internal faults (or power swings) will result in instantaneous tripping of the Zone 2 relays if the measured fault or power swing impedance falls within the zone 2 operating characteristic. These lines will trip on pilot Zone 2 for out-of-step conditions if the power swing impedance characteristic enters into Zone 2. All breakers are rated for out-of-phase switching.

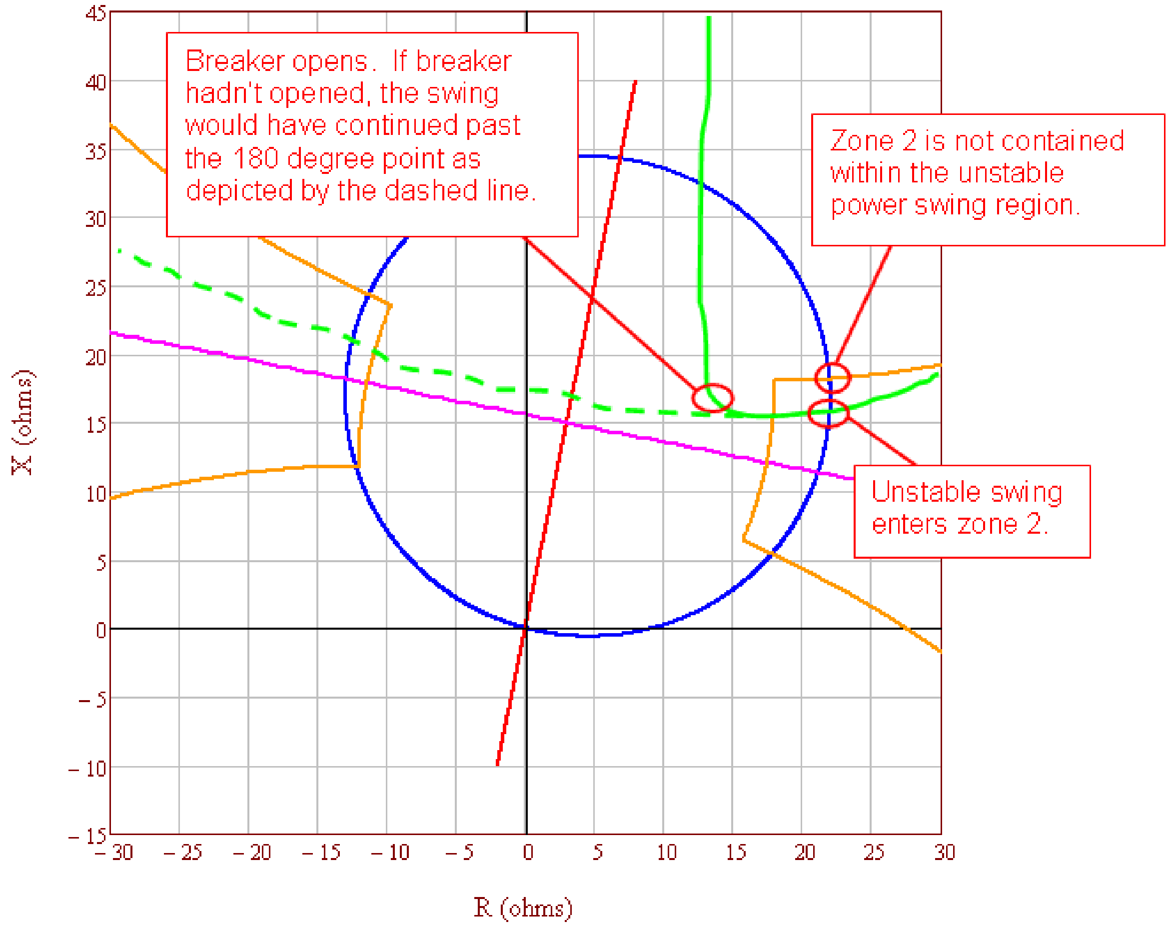

Figure 24: In this case, the Zone 2 element on circuit breakers 1, 2, 3, and 4 did not meet the PRC-026-1 – Attachment B criteria (this figure depicts the power swing as seen by relays on breakers 3 and 4).

In Figure 24, a large disturbance occurs within the small utility and its system goes out-of-step with the large interconnect. The small utility is importing power at the time of the disturbance. The actual power swing, as shown by the solid green line, enters the Zone 2 relay characteristic on the terminals of Lines 1, 2, 3, and 4 causing both lines to trip as shown in Figure 25.

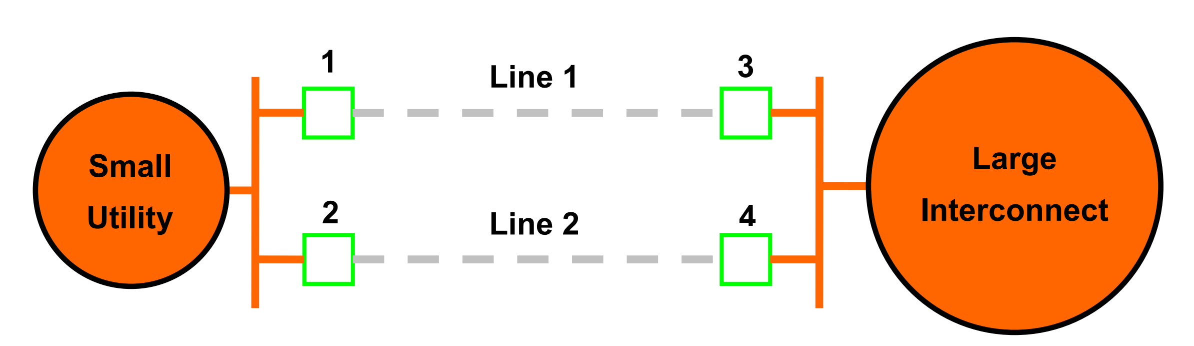

Figure 25: Islanding of the small utility due to Lines 1 and 2 tripping in response to an unstable power swing.

In Figure 25, the relays at circuit breakers 1, 2, 3, and 4 have correctly tripped due to the unstable power swing (shown by the dashed green line in Figure 24), de-energizing Lines 1 and 2, and creating an island between the small utility and the big interconnect. The small utility shed 500 MW of load on underfrequency and maintained a load to generation balance.

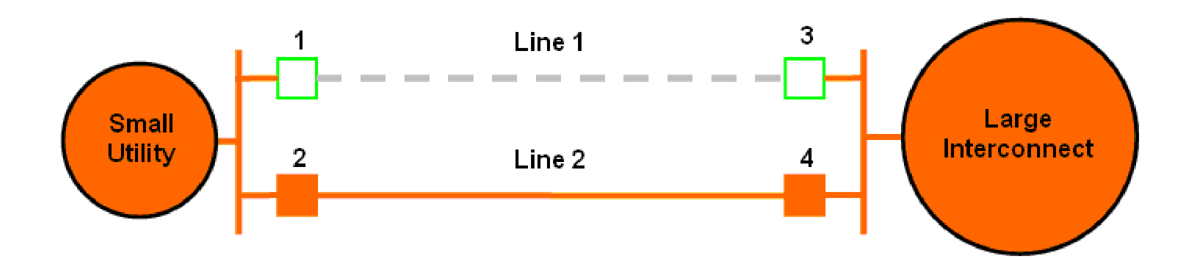

Figure 26: Line 1 is out-of-service for maintenance, Line 2 is loaded beyond its normal rating (but within its emergency rating).

Subsequent to the correct tripping of Lines 1 and 2 for the unstable power swing in Figure 25, another system disturbance occurs while the system is operating with Line 1 out-of-service for maintenance. The disturbance causes a stable power swing on Line 2, which challenges the relays at circuit breakers 2 and 4 as shown in Figure 27.

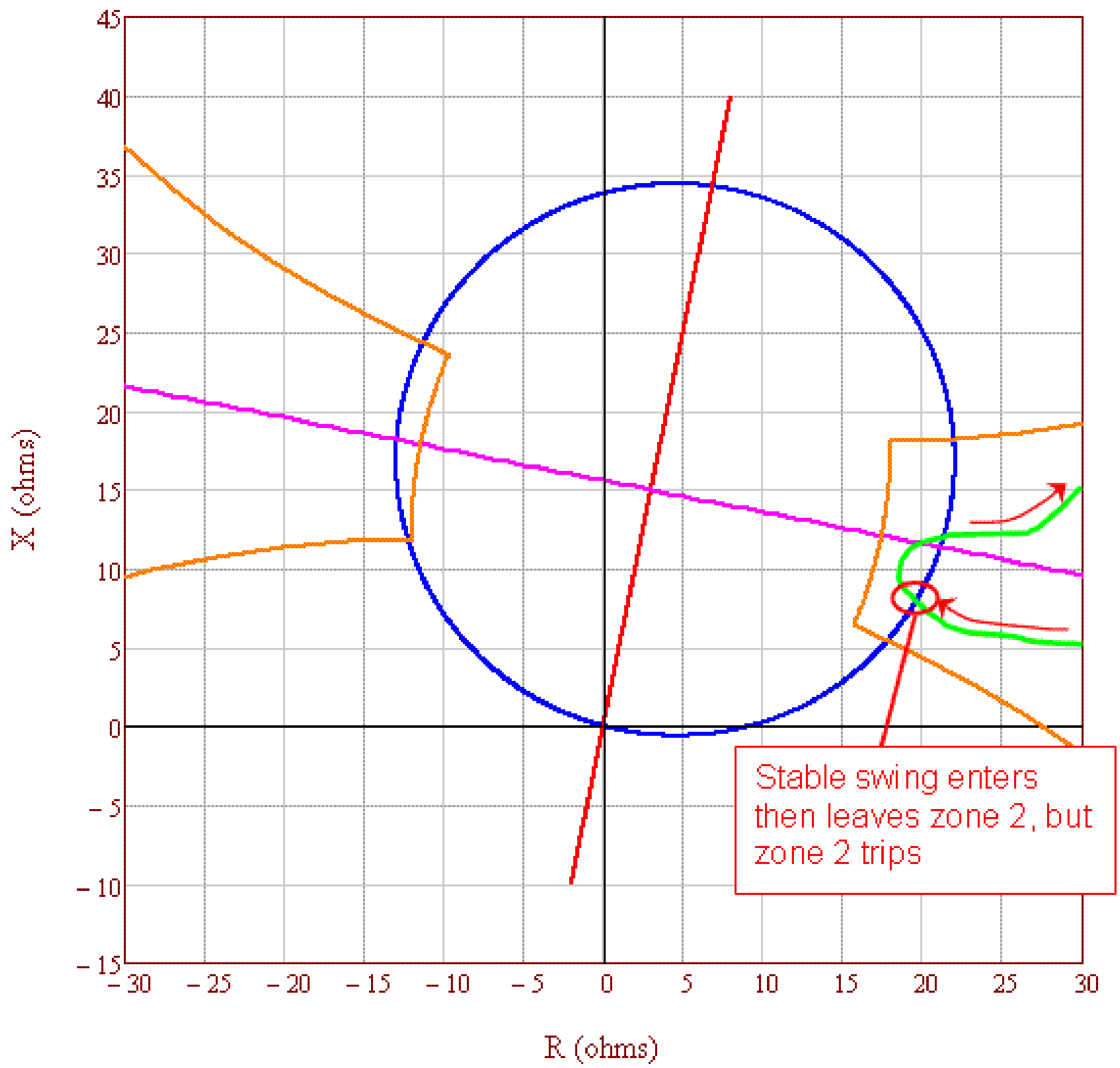

Figure 27: Relays on circuit breakers 2 and 4 were not addressed to meet the PRC-026-1 – Attachment B criteria following the previous unstable power swing event.

If the relays on circuit breakers 2 and 4 were not addressed under the Requirements for the previous unstable power swing condition, the relays would trip in response to the stable power swing, which would result in unnecessary system separation, load shedding, and possibly cascading or blackout.

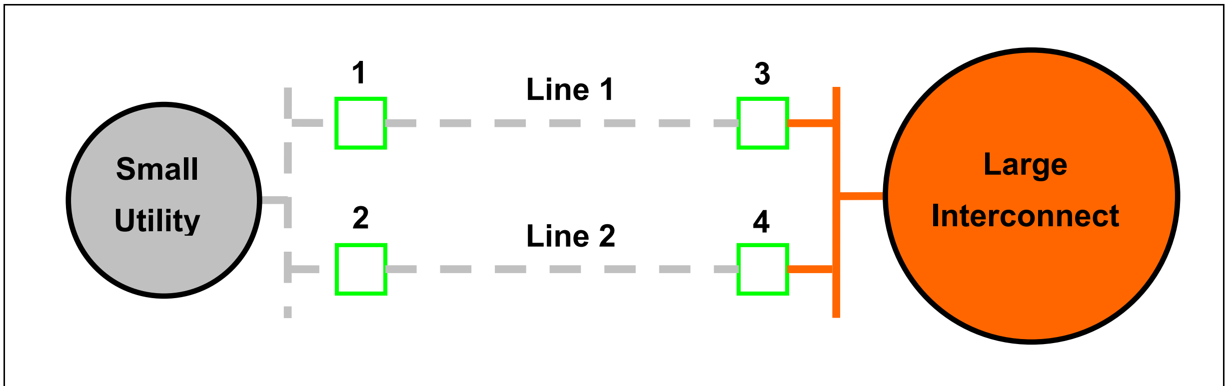

Figure 28: Possible blackout of the small utility.

If the relays that tripped in response to the previous unstable power swing condition in Figure 24 were addressed under the Requirements to meet PRC-026-1 - Attachment B criteria, the unnecessary tripping of the relays for the stable power swing shown in Figure 28 would have been averted, and the possible blackout of the small utility would have been avoided.

Rationale

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

Rationale for R1

The Planning Coordinator has a wide-area view and is in the position to identify generator, transformer, and transmission line BES Elements which meet the criteria, if any. The criteria-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013 ("PSRPS Report"),[31] which recommends a focused approach to determine an at-risk BES Element. See the Guidelines and Technical Basis for a detailed discussion of the criteria.

Rationale for R2

The Generator Owner and Transmission Owner are in a position to determine whether their load-responsive protective relays meet the PRC-026-1 – Attachment B criteria. Generator, transformer, and transmission line BES Elements are identified by the Planning Coordinator in Requirement R1 and by the Generator Owner and Transmission Owner following an actual event where the Generator Owner and Transmission Owner became aware (i.e., through an event analysis or

[31] NERC System Protection and Control Subcommittee, *Protection System Response to Power Swings*, August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf)

Protection System review) tripping was due to a stable or unstable power swing. A period of 12 calendar months allows sufficient time for the entity to conduct the evaluation.

Rationale for R3

To meet the reliability purpose of the standard, a CAP is necessary to ensure the entity's Protection System meets the PRC-026-1 – Attachment B criteria (1st bullet) so that protective relays are expected to not trip in response to stable power swings. A CAP may also be developed to modify the Protection System for exclusion under PRC-026-1 – Attachment A (2nd bullet). Such an exclusion will allow the Protection System to be exempt from the Requirement for future events. The phrase, "…while maintaining dependable fault detection and dependable out-of-step tripping…" in Requirement R3 describes that the entity is to comply with this standard, while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Rationale for R4

Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting CAP changes and completion of activities provides measurable progress and confirmation of completion.

Rationale for Attachment B (Criterion A)

The PRC-026-1 – Attachment B, Criterion A provides a basis for determining if the relays are expected to not trip for a stable power swing having a system separation angle of up to 120 degrees with the sending-end and receiving-end voltages varying from 0.7 to 1.0 per unit (See Guidelines and Technical Basis).

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-026-1 — Relay Performance During Stable Power Swings

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-026-1	R1.	01/01/2018	
PRC-026-1	R2.	01/01/2020	
PRC-026-1	2.1.	01/01/2020	
PRC-026-1	2.2.	01/01/2020	
PRC-026-1	R3.	01/01/2020	
PRC-026-1	R4.	01/01/2020	

Printed On: April 15, 2016, 02:47 PM

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

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

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.	

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**
2. **Number:** **TPL-001-5**
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

   - Planning Coordinator.
   - Transmission Planner.

5. ~~**Effective Date: See Implementation Plan.**~~

B. Requirements and Measures

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-032 standard, 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. New planned Facilities and changes to existing Facilities.

1.1.3. Real and reactive Load forecasts.

1.1.4. Known commitments for Firm Transmission Service and Interchange.

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

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using data consistent with MOD-032, 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.

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. 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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 assessed. Based upon this assessment, an analysis 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

2.4.5. 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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 2.1.3 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 Remedial Action Schemes.
- 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.

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.

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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 and 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.

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.

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 Remedial Action Scheme 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. 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.

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.

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.

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]*

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.

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]*

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.

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]*

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.

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.

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.

C. ~~Compliance~~

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.~~

~~**1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.~~

~~The applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

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

~~**1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.~~

~~**1.4. Compliance Monitoring Period and Reset Timeframe:**~~

~~Not applicable.~~

~~**1.5. Compliance Monitoring and Enforcement Processes:**~~

- ~~Compliance Audits~~
- ~~Self-Certifications~~
- ~~Spot Checks~~
- ~~Compliance Violation Investigations~~
- ~~Self-Report~~
- ~~Complaints~~

~~**1.6. Additional Compliance Information**~~

~~None.~~

~~Violation Severity Levels~~

~~R #~~	~~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 1.1.5.~~	~~The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.~~	~~The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.~~	~~The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5.~~ ~~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-032 standard 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,~~	~~The responsible entity failed to comply with two or more of the following Parts of~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
			~~Part 2.2, Part 2.4, Part 2.5, or Part 2.7.~~	~~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.~~ ~~OR~~ ~~The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.~~	~~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 Table 1.~~ ~~OR~~ ~~The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.~~	~~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.~~ ~~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~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~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~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~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.~~
~~**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~~	~~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~~	~~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~~	~~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.~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
	~~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.~~	~~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.~~	~~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.~~	~~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.~~

D. Regional Variances

None.

E. Associated Documents

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.	

Version	Date	Action	Change Tracking
		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.	
5	November 7, 2018	Adopted by the NERC Board of Trustees.	Revised to address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.
5.	January 23, 2020	FERC Order issued approving TPL-001-5. Docket No. RM19-10-000.	
5.1	June 10, 2020	FERC Order issued approving TPL-001-5.1. Docket No. RD20-8-000.	Errata

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

<table>
<tr><th>Category</th><th>Initial Condition</th><th>Event [1]</th><th>Fault Type [2]</th><th>BES Level [3]</th><th>Interruption of Firm Transmission Service Allowed [4]</th><th>Non-Consequential Load Loss Allowed</th></tr>
<tr><td rowspan="2">P3
Multiple Contingency</td><td rowspan="2">Loss of generator unit followed by System adjustments[9]</td><td>Loss of one of the following:
1. Generator
2. Transmission Circuit
3. Transformer[5]
4. Shunt Device[6]</td><td>3Ø</td><td rowspan="2">EHV, HV</td><td rowspan="2">No[9]</td><td rowspan="2">No[12]</td></tr>
<tr><td>5. Single pole of a DC line</td><td>SLG</td></tr>
<tr><td rowspan="3">P4
Multiple Contingency
(Fault plus stuck breaker[10])</td><td rowspan="3">Normal System</td><td rowspan="2">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</td><td rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus</td><td>SLG</td><td>EHV, HV</td><td>Yes</td><td>Yes</td></tr>
</table>

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[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>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>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.</td>
<td>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] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

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.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. i. 3Ø internal breaker fault. j. 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.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
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. For purposes of this standard, non-redundant components of a Protection System to consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment 1

I. 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

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

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.

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
2. **Number:** TPL-007-4
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.2.** Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
     - **4.1.3.** Transmission Owner who owns a Facility or Facilities specified in 4.2; and
     - **4.1.4.** Generator Owner who owns a Facility or Facilities specified in 4.2.
   - **4.2. Facilities:**
     - **4.2.1.** Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
5. ~~**Effective Date:** See Implementation Plan for TPL-007-4.~~
6. **Background:** During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

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 Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

7.4.2. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and

7.4.3. Updated timetable for implementing the selected actions in Part 7.1.

7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.3.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective GIC values to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

R11. Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective

Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

11.1. 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 Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

11.2. Be developed within one year of completion of the supplemental GMD Vulnerability Assessment.

11.3. Include a timetable, subject to approval for any extension sought under Part 11.4, for implementing the selected actions from Part 11.1. The timetable shall:

11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

11.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

11.4. Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following:

11.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

11.4.2. Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and

11.4.3. Updated timetable for implementing the selected actions in Part 11.1.

11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it submitted a request for extension to the CEA if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

GMD Measurement Data Processes

R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R12.

R13. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M13. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R13.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~**1.1. Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.~~

~~**1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

~~The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

- ~~For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.~~
- ~~For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.~~
- ~~For Requirement R7 and R11, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.~~
- ~~For Requirements R12 and R13, each responsible entity shall retain documentation as evidence for three years.~~

~~**1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.~~

Table 1: Steady State Planning GMD Event				
Steady State: a. Voltage collapse, Cascading and uncontrolled islanding shall not occur. b. Generation loss is acceptable as a consequence of the steady state planning GMD events. c. 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.				
Category	**Initial Condition**	**Event**	**Interruption of Firm Transmission Service Allowed**	**Load Loss Allowed**
Benchmark GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event – GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes
Table 1: Steady State Performance Footnotes				
1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information. 2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1. 3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.				

Violation Severity Levels

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.~~
~~R2.~~	~~N/A~~	~~N/A~~	~~The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the studies~~	~~The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the studies~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
			~~needed to complete benchmark and supplemental GMD Vulnerability Assessments.~~	~~needed to complete benchmark and supplemental GMD Vulnerability Assessments.~~
~~R3.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.~~
~~R4.~~	~~The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.~~	~~The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3;~~ ~~OR~~ ~~The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the~~	~~The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3;~~ ~~OR~~ ~~The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the~~	~~The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3;~~ ~~OR~~ ~~The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~last benchmark GMD Vulnerability Assessment.~~	~~last benchmark GMD Vulnerability Assessment.~~	~~GMD Vulnerability Assessment;~~ ~~OR~~ ~~The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.~~
~~R5.~~	~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.~~	~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.~~	~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.~~	~~The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area;~~ ~~OR~~ ~~The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.~~
~~R6.~~	~~The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power~~	~~The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly~~	~~The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and~~	~~The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
	~~transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.~~	~~owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;~~ ~~OR~~ ~~The responsible entity failed to include one of the~~	~~jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;~~ ~~OR~~ ~~The responsible entity failed to include two of the~~	~~applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;~~ ~~OR~~ ~~The responsible entity failed to include three of the required elements as listed~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~required elements as listed in Requirement R6, Parts 6.1 through 6.3.~~	~~required elements as listed in Requirement R6, Parts 6.1 through 6.3.~~	~~in Requirement R6, Parts 6.1 through 6.3.~~
~~R7.~~	~~The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.~~	~~The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.~~	~~The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.~~	~~The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5;~~ ~~OR~~ ~~The responsible entity did not develop a Corrective Action Plan as required by Requirement R7.~~
~~R8.~~	~~The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment.~~	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R8, Parts 8.1 through 8.3;~~ ~~OR~~ ~~The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more~~	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.3;~~ ~~OR~~ ~~The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more~~	~~The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.3;~~ ~~OR~~ ~~The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD Vulnerability Assessment.~~	~~than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.~~	~~than 72 calendar months since the last supplemental GMD Vulnerability Assessment;~~ ~~OR~~ ~~The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.~~
~~R9.~~	~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.~~	~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.~~	~~The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.~~	~~The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area;~~ ~~OR~~ ~~The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.~~
~~R10.~~	~~The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its~~	~~The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and~~	~~The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to~~	~~The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
	~~solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.~~	~~including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1~~ ~~OR~~	~~(and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1;~~ ~~OR~~	~~than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase;~~ ~~OR~~ ~~The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1;~~ ~~OR~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.~~	~~The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.~~	~~The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.~~
~~**R11.**~~	~~The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R11, Parts 11.1 through 11.5.~~	~~The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R11, Parts 11.1 through 11.5.~~	~~The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R11, Parts 11.1 through 11.5.~~	~~The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R11, Parts 11.1 through 11.5;~~ ~~OR~~ ~~The responsible entity did not develop a Corrective Action Plan as required by Requirement R11.~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R12.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.~~
~~R13.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area~~.

D. Regional Variances

D.A. Regional Variance for Canadian Jurisdictions

This Variance shall be applicable in those Canadian jurisdictions where the Variance has been approved for use by the applicable governmental authority or has otherwise become effective in the jurisdiction.

This variance replaces all references to "Attachment 1" in the standard with "Attachment 1 or Attachment 1-CAN."

In addition, this Variance replaces Requirement R7, Part 7.3 through Part 7.5 and Requirement R11, Part 11.3 through Part 11.5 with the following:

D.A.7.3. Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1. The timetable shall:

D.A.7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.7.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.7.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.7.3. The revised CAP shall document the following:

D.A.7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity;

D.A.7.4.2 Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable; and

D.A.7.4.3 Updated timetable for implementing the selected actions in Part 7.1.

D.A.7.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision.

D.A.7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.7.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

D.A.11.3. Include a timetable, subject to revision by the responsible entity in Part D.A.11.4, for implementing the selected actions from Part 11.1. The timetable shall:

D.A.11.3.1. Specify implementation of non-hardware mitigation, if any, within two years of the later of the development of the CAP or receipt of regulatory approvals, if required; and

D.A.11.3.2. Specify implementation of hardware mitigation, if any, within four years of the later of the development of the CAP or receipt of regulatory approvals, if required.

D.A.11.4. Be revised if the responsible entity is unable to implement the CAP within the timetable for implementation provided in Part D.A.11.3. The revised CAP shall document the following:

D.A.11.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity;

D.A.11.4.2 Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures if applicable; and

D.A.11.4.3 Updated timetable for implementing the selected actions in Part 11.1.

D.A.11.5. Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision.

D.A.11.5.1. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

D.A.M.11. Each responsible entity, as determined in Requirement R1, that concludes, through the supplemental GMD Vulnerability Assessment conducted in Requirement R8, that the responsible entity's System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R11. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R11, and (iii) to the Compliance Enforcement Authority or Applicable Governmental Authority when revised under D.A.11.4 within 90 calendar days of revision. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R11.

E. Associated Documents

Attachment 1

Attachment 1-CAN

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	New
2	November 9, 2017	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order No. 830.
2	November 25, 2018	FERC Order issued approving TPL-007-2. Docket No. RM18-8-000	
3	February 7, 2019	Adopted by the NERC Board of Trustees	Canadian Variance
4	February 6, 2020	Adopted by the NERC Board of Trustees	Revised to respond to directives in FERC Order. 851
4	March 19, 2020	FERC Order issued approving TPL-007-4. Docket No. RD20-3-000	

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta_b \ (V/km) \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_s \ (V/km) \quad (2)$$

where, α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression:

$$\alpha = 0.001 \times e^{(0.115 \times L)} \quad (3)$$

where, L is the geomagnetic latitude in degrees and $0.1 \le \alpha \le 1$.

[1] The Benchmark Geomagnetic Disturbance Event Description, May 2016 is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/Stand/TPL0071RD/Benchmark_clean_May12_complete.pdf.

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental Geomagnetic Disturbance Event Description, October 2017 white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2: Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the responsible entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

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[3] Available at the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$$\beta_b = E/8 \text{ for the benchmark GMD event} \quad (4)$$

$$\beta_s = E/12 \text{ for the supplemental GMD} \quad (5)$$

where, *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/.

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project webpage: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

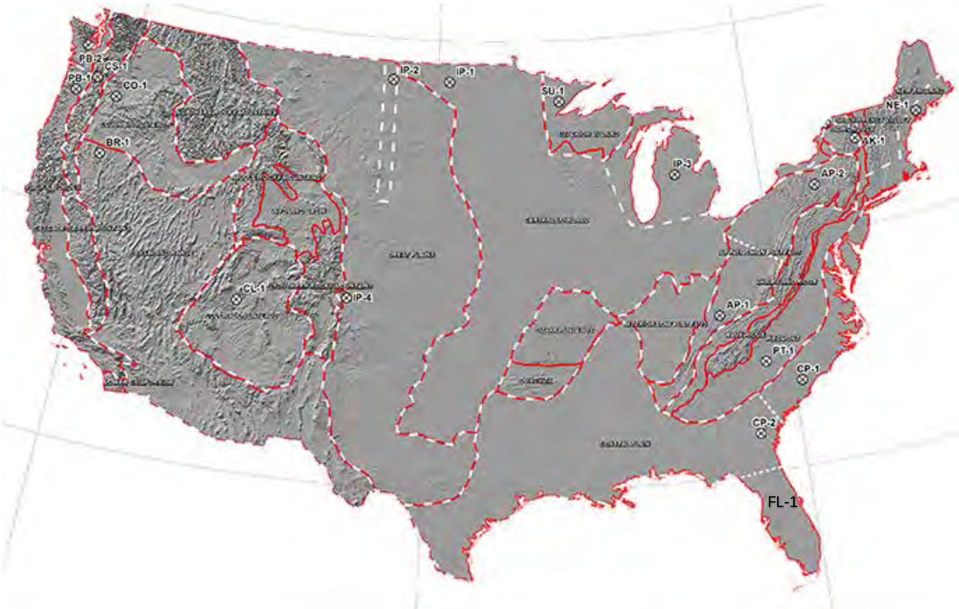


Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

[6] Additional map detail is available at the U.S. Geological Survey: http://geomag.usgs.gov/.

Table 3: Geoelectric Field Scaling Factors		
Earth model	**Scaling Factor Benchmark Event (β_b)**	**Scaling Factor Supplemental Event (β_s)**
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

Table 4: Reference Earth Model (Quebec)	
Layer Thickness (km)	**Resistivity (Ω-m)**
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event[7]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds.[8] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor β_b.

[7] Refer to the Benchmark Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.
[8] The data file of the benchmark geomagnetic field waveform is available on the Related Information webpage for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx.

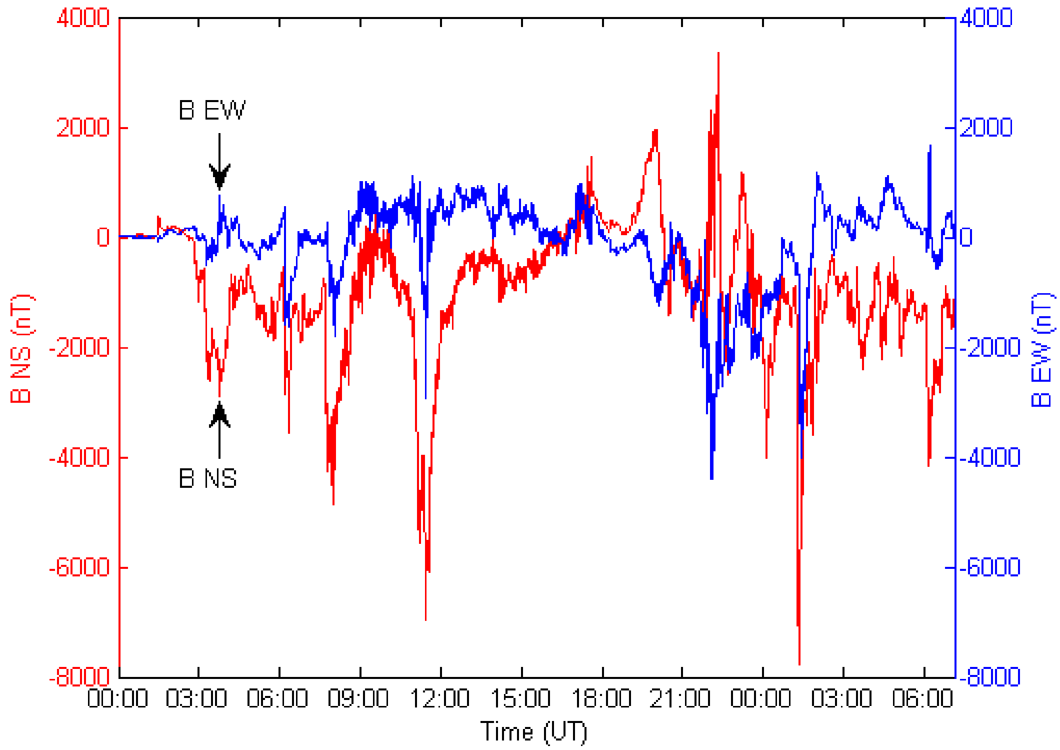


Figure 3: Benchmark Geomagnetic Field Waveform
Red B_n (Northward), Blue B_e (Eastward)

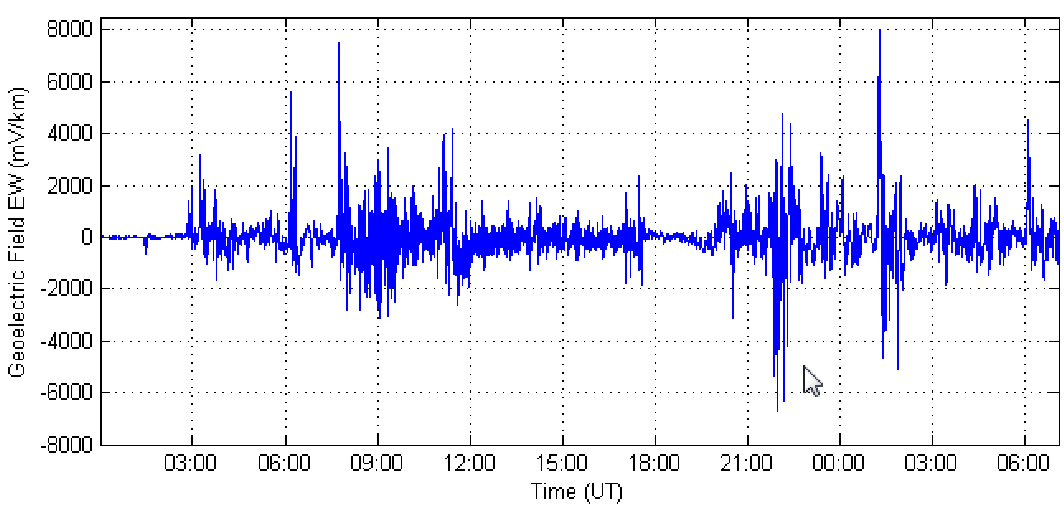


Figure 4: Benchmark Geoelectric Field Waveform
E_E (Eastward)

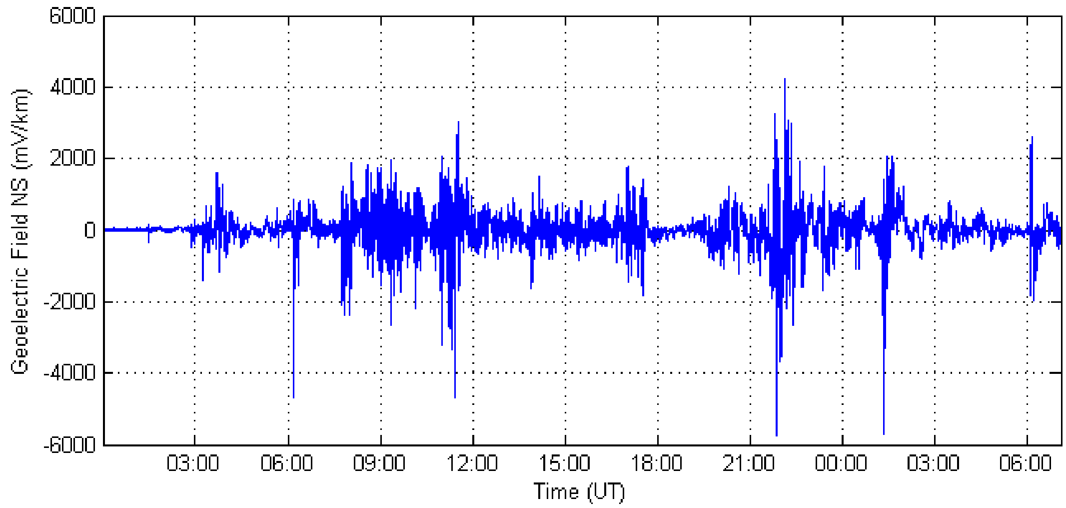


Figure 5: Benchmark Geoelectric Field Waveform
E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[9]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at the NRCan Ottawa geomagnetic observatory, is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[10] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_S.

[9] Refer to the Supplemental Geomagnetic Disturbance Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

[10] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project webpage: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx.

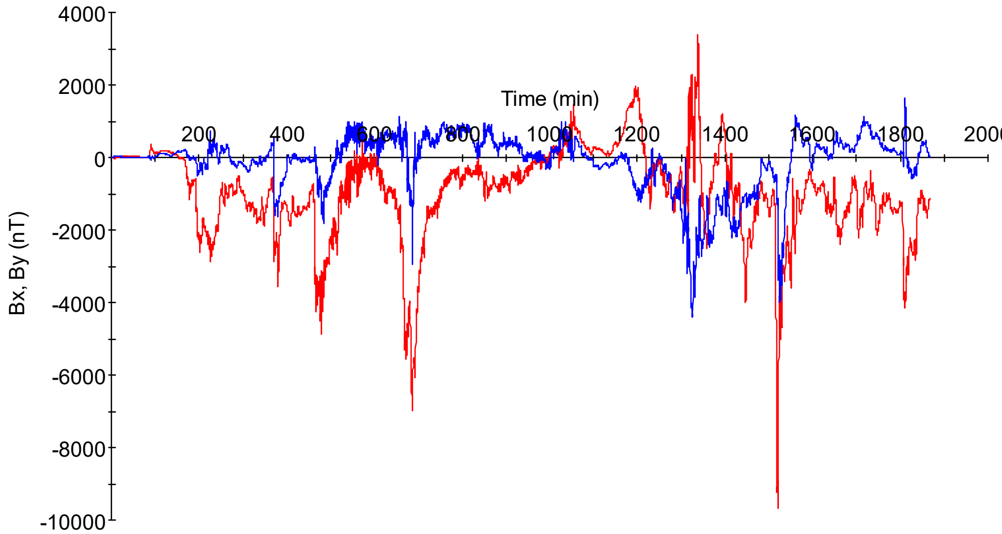


Figure 6: Supplemental Geomagnetic Field Waveform
Red B_N (Northward), Blue B_E (Eastward)

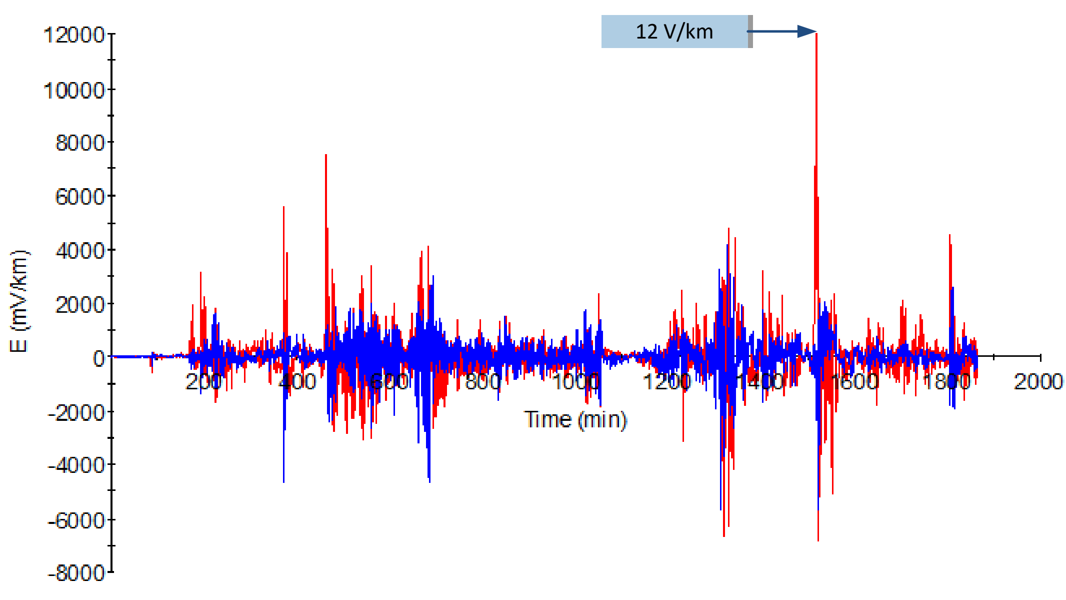


Figure 7: Supplemental Geoelectric Field Waveform
Blue E_N (Northward), Red E_E (Eastward)

Attachment 1-CAN

Attachment 1-CAN provides an alternative that a Canadian entity may use in lieu of the benchmark or supplemental GMD event(s) defined in Attachment 1 for performing GMD Vulnerability Assessment(s).

A Canadian entity may use the provisions of Attachment 1-CAN if it has regionally specific information that provides a technically justified means to re-define a 1-in-100 year GMD planning event(s) within its planning area.

Information for the Alternative Methodology

GMD Vulnerability Assessment(s) require the use of geophysical and engineering models. Canadian-specific data is available and growing. Ongoing research allows for more accurate characterization of regional parameters used in these models. Such Canadian-specific data includes geomagnetic field, earth conductivity, and geomagnetically induced current measurements that can be used for modeling and simulation validation.

Information used to calculate geoelectric fields for the benchmark and supplemental GMD events shall be clearly documented and technically justified. For example, the factors involved in the calculation of geoelectric fields are geomagnetic field variations and an earth transfer function(s).[1] Technically justified information used in modelling geomagnetic field variations may include: technical documents produced by governmental entities such as Natural Resources Canada; technical papers published in peer-reviewed journals; and data sets gathered using sound scientific principles. An earth transfer function may rely on magnetotelluric measurements or earth conductivity models.

Modeling assumptions shall also be clearly documented and technically justified. An entity may use sensitivity analysis to identify how the assumptions affect the results.

A simplified model may be used to perform a GMD Vulnerability Assessment(s), as long as the model is more conservative than a more detailed model.

When interpreting assessment results, the entity shall consider the maturity of the modeling, toolset, and techniques applied.

Geomagnetic Disturbance Planning Events

The 1-in-100 year planning event shall be based on regionally specific data and technically justifiable statistical analyses (e.g., extreme value theory) and applied to the benchmark and supplemental GMD Vulnerability Assessment(s).

For the benchmark GMD Vulnerability Assessment(s), an entity shall consider the large-scale spatial structure of the GMD event. For the supplemental GMD Vulnerability Assessment(s), an

[1] The "earth transfer function" is the relationship between the electric fields and magnetic field variations at the surface of the earth.

entity shall consider the small-scale spatial structure of the GMD event (e.g., using magnetometer measurements or realistic electrojet calculations).

BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

Appendix A-2

Reliability Standards Assessed by BC Hydro

Red-lined

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-~~1~~2

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

~~1. **Effective Date:** January 1, 2007~~

~~5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).~~

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.

R2. Each Transmission Operator ~~and Balancing Authority~~ shall establish plans for automatic load shedding for ~~underfrequency or~~ undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.

R4. A Transmission Operator ~~or Balancing Authority~~ shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: ~~frequency, rate of frequency decay,~~ voltage level, rate of voltage decay, or power flow levels.

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.

R7. The Transmission Operator ~~and Balancing Authority~~ shall coordinate automatic undervoltage load shedding throughout their areas with ~~underfrequency isolation of generating units,~~ tripping of shunt capacitors, and other automatic actions that will occur under abnormal ~~frequency,~~ voltage, or power flow conditions~~.~~

R8. Each Transmission Operator or Balancing Authority shall have plans for operator ~~-~~controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

M1. Each Transmission Operator ~~and Balancing Authority~~ that has or directs the deployment of undervoltage ~~and/or underfrequency~~ load shedding facilities, shall have and provide upon request, its automatic load shedding plans~~.(~~. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

~~**1.2. Compliance Monitoring and Reset Time Frame**~~

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

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

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

~~**1.3. Additional Reporting Requirement**~~

~~No additional reporting required.~~

~~**1.4. Data Retention**~~

~~Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.~~

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

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

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

~~**1.5. Additional Compliance Information**~~

~~None.~~

2. Violation Severity Levels ~~of Non-Compliance:~~

~~**1.1. Level 1:** Not applicable.~~

~~**1.2. Level 2:** Not applicable.~~

~~**1.3. Level 3:** Not Applicable.~~

~~**1.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**1.4.1** Does not have an automatic load shedding plan as specified in R2.~~

~~**1.4.2** Does not have manual load shedding plans as specified in R8.~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to shed customer load.~~
~~R2~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~requirement.~~
~~R3.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.~~	~~The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.~~
~~R4.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.~~
~~R5.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.~~
~~R6.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R7.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.~~	~~The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.~~
~~R8.~~	~~N/A~~	~~The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.~~	~~The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.~~	~~The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.~~

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Modified R4, R5, R6 and associated VSLs for R2, R4, and R7to clarify that the requirements don’t apply to automatic underfrequency load shedding	Revised to eliminate redundancies with PRC-006-1

A. Introduction

1. **Title:** ~~Technical Assessment of the Design and Effectiveness of~~ Undervoltage Load Shedding ~~Program.~~

2. **Number:** PRC-010-~~0~~2

3. **Purpose:** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of ~~Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an~~ Undervoltage Load Shedding (UVLS) programs.

4. **Applicability:**

   4.1. Planning Coordinator.~~Load-Serving Entity that operates a UVLS program~~

   4.2. Transmission Planner.~~Owner that owns a UVLS program~~

   4.3. Undervoltage load shedding (UVLS) entities – Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator~~Transmission Operator that operates a UVLS program~~

   ~~**4.4.** Distribution Provider that owns or operates a UVLS program~~

5. ~~**Effective Date:** See Project 2008-02.2 Implementation Plan. April 1, 2005~~

B. Requirements and Measures

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).~~

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2 The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.~~**R1.1.** This assessment shall include, but is not limited to:~~

~~**R1.1.1.** Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.~~

~~**R1.1.2.** Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.~~

~~**R1.1.3.** A review of the voltage set points and timing.~~

M1. Acceptable evidence may include, but is not limited to, date-stamped studies and analyses, reports, or other documentation detailing the effectiveness of the UVLS Program, and date-stamped communications showing that the UVLS Program specifications and implementation schedule were provided to UVLS entities.

R2. Each UVLS entity shall adhere to the UVLS Program specifications and implementation schedule determined by its Planning Coordinator or Transmission Planner associated with UVLS Program development per Requirement R1 or with any Corrective Action Plans per Requirement R5. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days). (Retirement approved by FERC effective January 21, 2014.)~~

M2. Acceptable evidence must include date-stamped documentation on the completion of actions and may include, but is not limited to, identifying the equipment armed with UVLS relays, the UVLS relay settings, associated Load summaries, work management program records, work orders, and maintenance records.

R3. Each Planning Coordinator or Transmission Planner shall perform a comprehensive assessment to evaluate the effectiveness of each of its UVLS Programs at least once every 60 calendar months. Each assessment shall include, but is not limited to, studies and analyses that evaluate whether: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. The UVLS Program resolves the identified undervoltage issues for which the UVLS Program is designed.

3.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

M3. Acceptable evidence may include, but is not limited to, date-stamped reports or other documentation detailing the assessment of the UVLS Program.

R4. Each Planning Coordinator or Transmission Planner shall, within 12 calendar months of an event that resulted in a voltage excursion for which its UVLS Program was designed to operate, perform an assessment to evaluate: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and

4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.

M4. Acceptable evidence may include, but is not limited to, date-stamped event data, event analysis reports, or other documentation detailing the assessment of the UVLS Program and associated equipment.

R5. Each Planning Coordinator or Transmission Planner that identifies deficiencies during an assessment performed in either Requirement R3 or R4 shall develop a Corrective Action Plan to address the deficiencies and subsequently provide the Corrective Action Plan, including an implementation schedule, to UVLS entities within three calendar months of completing the assessment. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Acceptable evidence must include a date-stamped Corrective Action Plan that addresses identified deficiencies and may also include date-stamped reports or other documentation supporting the Corrective Action Plan. Evidence should also include date-stamped communications showing that the Corrective Action Plan and an associated implementation schedule were provided to UVLS entities.

R6. Each Planning Coordinator that has a UVLS Program in its area shall update a database containing data necessary to model the UVLS Program(s) in its area for use in event analyses and assessments of the UVLS Program at least once each calendar year. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, date-stamped spreadsheets, database reports, or other documentation demonstrating a UVLS Program database was updated.

R7. Each UVLS entity shall provide data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of a UVLS Program database. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating data was provided to the Planning Coordinator as specified.

R8. Each Planning Coordinator that has a UVLS Program in its area shall provide its UVLS Program database to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of a written request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M8. Acceptable evidence may include, but is not limited to, date-stamped emails, letters, or other documentation demonstrating that the UVLS Program database was provided within 30 calendar days of receipt of a written request.

~~C. Measures~~

~~**M1.** Each Transmission Owner's and Distribution Provider's UVLS program shall include the elements identified in Reliability Standard PRC-010-0_R1.~~

~~**M2.** Each Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided~~

~~documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC as specified in Reliability Standard PRC-010-0_R2. (Retirement approved by FERC effective January 21, 2014.)~~

~~D.~~C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1.~~ **Compliance ~~Monitoring Responsibility~~~~Enforcement Authority~~**

~~As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards~~~~Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.~~

~~1.2. Evidence Retention~~~~Compliance Monitoring Period and Reset Timeframe~~

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

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

~~The applicable entity shall retain documentation as evidence for six calendar years.~~

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

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

~~Assessments every five years or as required by System changes. Current assessment on request (30 calendar days.)~~

~~1.3. Data Retention~~~~Compliance Monitoring and Assessment Processes~~

~~"Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~ ~~None specified.~~

~~**1.4. Additional Compliance Information**~~

~~None.~~

~~2. Levels of Non-Compliance~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2:** Not applicable.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** An assessment of the UVLS program did not address one of the requirements listed in Reliability Standard PRC-010-0_R1.1 or an assessment of the UVLS program was not provided~~.

~~Table of Compliance Elements~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~Long-term Planning~~	~~High~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The applicable entity that developed the UVLS Program failed to evaluate the program's effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to UVLS entities in accordance with Requirement R1, including the items specified in Parts 1.1 and 1.2.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R2~~	~~Long-term Planning~~	~~High~~	~~N/A~~	~~N/A~~	~~The applicable entity failed to adhere to the UVLS Program specifications in accordance with Requirement R2.~~ ~~OR~~ ~~The applicable entity failed to adhere to the implementation schedule in accordance with Requirement R2.~~	~~The applicable entity failed to adhere to the UVLS Program specifications and implementation schedule in accordance with Requirement R2.~~
~~R3~~	~~Long-term Planning~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The applicable entity failed to perform an assessment at least once during the 60 calendar months in accordance with Requirement R3, including the items specified in Parts 3.1 and 3.2.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R4~~	~~Operations Planning~~	~~Medium~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 12 calendar months but less than or equal to 13 calendar months after an applicable event.~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 13 calendar months but less than or equal to 14 calendar months after an applicable event.~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 14 calendar months but less than or equal to 15 calendar months after an applicable event.~~	~~The applicable entity performed an assessment in accordance with Requirement R4 within a time period greater than 15 calendar months after an applicable event.~~ ~~OR~~ ~~The applicable entity failed to perform an assessment in accordance with Requirement R4.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R5~~	~~Operations Planning~~	~~Medium~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by less than or equal to 15 calendar days.~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 15 calendar days but less than or equal to 30 calendar days.~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 30 calendar days but less than or equal to 45 calendar days.~~	~~The applicable entity developed a Corrective Action Plan and provided it to UVLS entities in accordance with Requirement R5 but was late by more than 45 calendar days.~~ ~~OR~~ ~~The responsible entity failed to develop a Corrective Action Plan or provide it to UVLS entities in accordance with Requirement R5.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R6~~	~~Operations Planning~~	~~Lower~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by less than or equal to 30 calendar days.~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by more than 30 calendar days but less than or equal to 60 calendar days.~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by more than 60 calendar days but less than or equal to 90 calendar days.~~	~~The applicable entity updated the database in accordance with Requirement R6 but was late by more than 90 calendar days.~~ ~~OR~~ ~~The applicable entity failed to update the database in accordance with Requirement R6.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R7~~	~~Operations Planning~~	~~Lower~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by less than or equal to 30 calendar days per the specified schedule.~~ ~~OR~~ ~~The applicable entity provided data in accordance with Requirement R7 but the data was not provided according to the specified format.~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by more than 30 calendar days but less than or equal to 60 calendar days per the specified schedule.~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by more than 60 calendar days but less than or equal to 90 calendar days per the specified schedule.~~	~~The applicable entity provided data in accordance with Requirement R7 but was late by more than 90 calendar days per the specified schedule.~~ ~~OR~~ ~~The applicable entity failed to provide data in accordance with Requirement R7.~~

~~R #~~	~~Time Horizon~~	~~VRF~~	~~Violation Severity Levels~~			
			~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R8~~	~~Operations Planning~~	~~Lower~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by less than or equal to 15 calendar days.~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 15 calendar days but less than or equal to 30 calendar days.~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 30 calendar days but less than or equal to 45 calendar days.~~	~~The applicable entity provided its UVLS Program database in accordance with Requirement R8 but was late by more than 45 calendar days.~~ ~~OR~~ ~~The applicable entity failed to provide its UVLS Program database in accordance with Requirement R8.~~

~~E.~~D. Regional Differences

~~1.~~ None~~ identified~~.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	April 1, 2005	Effective Date	New
~~0~~	~~February 8, 2005~~	~~Adopted by NERC Board of Trustees~~	
~~0~~	~~March 16, 2007~~	~~Approved by FERC~~	
0	February 7, 2013	Adopted by NERC Board of Trustees~~R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.~~	R2 and associated elements for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.
~~0~~	~~November 21, 2013~~	~~R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)~~	

1	November 13, 2014	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763.
2	May 7, 2015	Adopted by NERC Board of Trustees	Revisions made under Project 2008-02.2: Undervoltage Load Shedding (UVLS): Misoperation to include UVLS equipment.
2	November 19, 2015	FERC Letter Order issued approving PRC-010-2. Docket RD15-5-000	

Guidelines and Technical Basis

Introduction

The standard drafting team provides the following discussion to support the approach to the standard. The information is meant to enhance the understanding of the reliability needs and deliverable expectations of each requirement, supported as necessary by technical principles and industry experience.

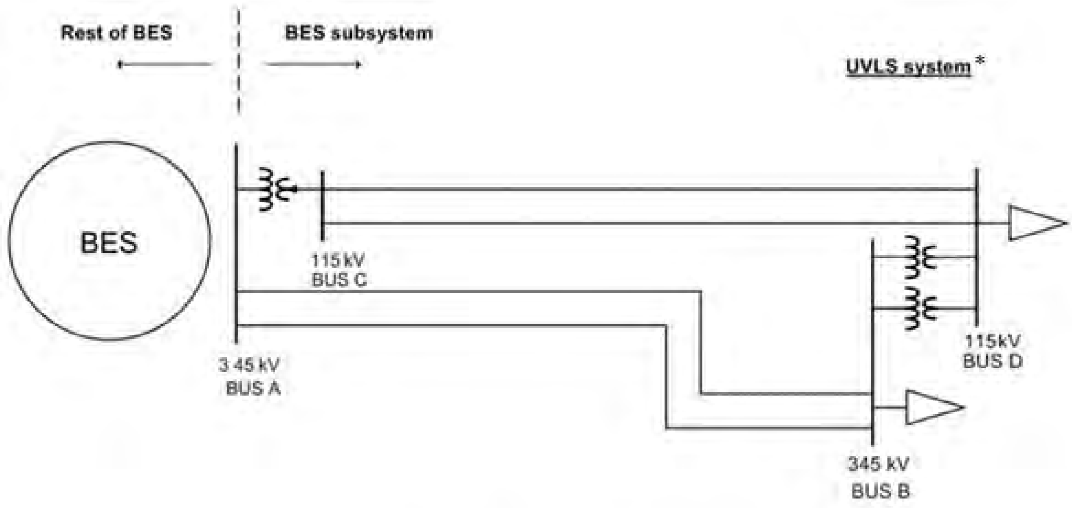
Guidelines for UVLS Program Definition

The definition for the term, "Undervoltage Load Shedding Program" or "UVLS Program" includes automatic load shedding programs that utilize only voltage inputs at locations where action is taken to shed load. As such, the failure of a single component is unlikely to affect the reliable operation of the program.

The UVLS Program definition excludes centrally controlled undervoltage-based load shedding, which utilizes inputs from multiple locations and may also utilize inputs other than voltages (such as generator reactive reserves, facility loadings, equipment statuses, etc.). The design and characteristics of a centrally controlled undervoltage-based load shedding system are the same as that of a Remedial Action Scheme (RAS), wherein load shedding is the remedial action. Therefore, just like for a RAS, the failure of a single component can compromise the reliable operation of centrally controlled undervoltage-based load shedding.

To ensure that the applicability of the standard includes only those undervoltage-based load shedding systems whose performance has an impact on system reliability, a UVLS Program must mitigate risk of one or more of the following: voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). An example of a program that would not fall under this category is undervoltage-based load shedding installed to mitigate damage to equipment or local loads that are directly affected by the low voltage event.

Figure 1 below is an example of a BES subsystem for which a UVLS system could be used as a solution to mitigate various issues following the loss of the 345 kV double circuit line between buses A and B. If the consequence of this Contingency does not impact the BES by leading to voltage instability, voltage collapse, or Cascading, a UVLS system (installed at either, or both, bus B and D) used to mitigate this Contingency would not fall under the definition of a UVLS Program. However, if this same UVLS system is used to mitigate an Adverse Reliability Impact outside this contained area, it would be classified as a wide-area undervoltage problem and would fall under the definition of UVLS Program.



*UVLS systems may be installed at either, or both, bus B and D

Figure 1: UVLS Subsystem

Guidelines for Requirements

Table 1 provides a high-level overview of the requirements contained in the standard.

Table 1: High-Level Requirement Overview

Requirement	Entity	Evaluate Program Effectiveness	Adhere to Program Specifications and Schedule	Perform Program Assessment (Periodic or Performance)	Develop a CAP to Address Program Deficiencies	Update and/or Share Program Data
R1	PC or TP	X				
R2	UVLS entity		X			
R3	PC or TP	X		X		
R4	PC or TP	X		X		
R5	PC or TP				X	
R6	PC					X
R7	UVLS entity					X
R8	PC					X

Guidelines for Requirement R1

A UVLS Program may be developed and implemented to either serve as a safety net system protection measure against unforeseen extreme Contingencies or to achieve specific system performance for known transmission Contingencies for which dropping of load is allowed under Transmission Planning (TPL) Reliability Standards. Regardless of the purpose, it is important that the UVLS Program being implemented is effective in terms that it mitigates undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Consideration should be given to voltage set points and time delays, rate of voltage decay or recovery, power flow levels, etc. when designing a UVLS Program.

For the UVLS Program to be effective in achieving its goal, it is also necessary that the UVLS Program is coordinated with generator voltage ride-through capabilities and other protection and control systems that may have an impact on the performance of the UVLS Program. Some of these protection and control systems may include, but are not limited to, transmission line protection, RAS, other undervoltage-based load shedding programs, autoreclosing, and controls of shunt capacitors, reactors, and static voltampere-reactive systems (SVSs).

For example, if the purpose of a UVLS Program is to mitigate fault-induced delayed voltage recovery (FIDVR) events in a large load center that also includes local generation, it is important that such a UVLS Program is coordinated with local generators' voltage ride-through capabilities. Generators in the vicinity of a load center are critical to providing dynamic voltage support to the system during FIDVR events. To maximize the benefit of on-line generation, the best practice may be to shed load prior to generation trip. However, occasionally, it may be best to let generation trip prior to load shed. Therefore, the impact of generation tripping should be considered while designing a UVLS Program.

Another example that can be highlighted is the coordination of a UVLS Program with automatic shunt reactor tripping devices if there are any on the system. Most likely, any shunt reactors on the system will trip off automatically after some time delay during low voltage conditions. In such cases, shunt reactors should be tripped before the load is shed to preserve the system. This may require coordination of time delays associated with the UVLS Program with shunt reactor tripping devices.

The examples given above demonstrate that, for a UVLS Program to be effective, proper consideration should be given to coordination of a UVLS Program with generator ride-through capabilities and other protection and control systems.

Guidelines for Requirement R2

Once a Planning Coordinator (PC) or Transmission Planner (TP) has identified a need for a UVLS Program, the Planning Coordinator or Transmission Planner will develop a program that includes specifications and an implementation schedule, which are then provided to UVLS entities per Requirement R1. Specifications may include voltage set points, time delays, amount of load to be shed, and the location at which load needs to be shed. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal. The UVLS entity must document that all necessary actions were completed to implement the UVLS Program.

Similarly, when a Corrective Action Plan (CAP) to address UVLS Program deficiencies is developed by the Planning Coordinator or Transmission Planner and provided to UVLS entities per Requirement R5, UVLS entities must comply with the CAP and its associated implementation schedule to ensure that the UVLS Program is effective. The UVLS entity is required to complete the actions specified in the CAP, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

Deferrals or other relevant changes to the UVLS Program specifications or CAP need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of a successful execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports, or other evidence.

For example, documentation of a CAP provides an auditable progress and completion confirmation for the identified UVLS Program deficiency:

CAP Example 1 - Corrective actions for a quick triggering problem; preemptive actions for similar installations:

The PC or TP obtains fault records from a UVLS entity that participates in its UVLS Program that indicate a group of UVLS relays triggered at the appropriate undervoltage level but with shorter delays than expected. The PC or TP directed the UVLS entity to schedule on-site inspections within three weeks. The results of the inspection confirmed that the delay-time programmed on the relays was 60 cycles instead of 90 cycles. The PC or TP then directed the UVLS entity to correct to a 90-cycle time delay setting of the UVLS relays identified to have shorter time delay settings within eight weeks.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to verify and adjust all remaining UVLS relays time delay settings within a one-year period.

The PC or TP verified completion of verification and adjustment of the time delay settings for all of the UVLS entity's equipment that participates in the PC or TP UVLS Program

CAP Example 2 - Corrective actions for a firmware problem; preemptive actions for similar installations:

The PC or TP obtains fault records on 6/4/2014 from a UVLS entity that participates in its UVLS Program. The UVLS entity also provided the fault records to the manufacturer, who responded on 6/11/2014 that the Misoperation[1] of the UVLS relay was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. The PC or TP approved the UVLS entity's plan to schedule Version 3 firmware installation on 6/12/2014.

[1] Misoperation of Protection Systems reporting was initiated by the NERC Board of Trustees adopted NERC Rules of Procedure, Section 1600, Request for Data or Information. Refer to: *Request for Data of Information, Protection System Misoperation Data Collection*, August 14, 2014. http://www.nerc.com/pa/RAPA/ProctectionSystem Misoperations/PRC-004-3%20Section%201600%20Data%20Request_20140729.pdf.

Applicability to other UVLS relays: The PC or TP then developed a schedule with the UVLS entity to install firmware version 3 at all of the UVLS entity's UVLS relays that are determined to be programmed with version 2 firmware. The completion date was scheduled no-later-than 12/31/2014.

The firmware replacements were completed on 12/4/2014.

Guidelines for Requirement R3

In addition to the initial studies required to develop a UVLS Program, periodic comprehensive assessments (detailed analyses) are required to ensure its continued effectiveness. This assessment is required to be completed at least once every 60 calendar months to capture the accumulated effects of minor changes to the system that have occurred since the last assessment was completed. However, at any point in time, a Planning Coordinator or Transmission Planner may also determine that a material change[2] to system topology or operating conditions affects the performance of the UVLS Program and therefore necessitates the same comprehensive assessment. Regardless of the trigger, each assessment should include an evaluation of each UVLS Program to ensure the continued integration through coordination.

This comprehensive assessment complements the TPL-001-4 annual assessment requirement to evaluate the impact of protection systems. The 60-month period is the same time frame used in TPL-001-4 and in PRC-006-1.

As specified in Requirement R3, a comprehensive assessment must be performed at least once every 60 calendar months. If a Planning Coordinator or Transmission Planner conducts a comprehensive assessment sooner for the reasons discussed above, the 60-month time period would restart upon completion of this assessment.

Guidelines for Requirement R4

After a voltage excursion event, the goal of the assessment required in Requirement R4 is to evaluate: (1) whether the UVLS Program resolved the undervoltage issues, and (2) the performance of the UVLS Program equipment. The assessment should include event data analysis, such as the relevant sequence of events leading to the undervoltage conditions (e.g., Contingencies, operation of protection systems, and RAS) and field measurements useful to analyzing the behavior of the system. A comprehensive description of the UVLS Program operation should be presented, including conditions of the trigger (e.g., voltage levels, time delays) and amount of load shed for each affected substation. Assessment of the event is performed to evaluate the level of performance of the program for the event of interest and to identify deficiencies to be included in a CAP per Requirement R5. Misoperation of UVLS equipment is addressed as a deficiency. Reporting of UVLS equipment Misoperations are

[2] It is understood that the term material change is not transportable on a continent-wide basis. This determination must be made by the Planning Coordinator or Transmission Planner and should be accompanied by documentation to support the technical rationale for determining material changes.

addressed by the NERC *Request for Data and Information, Protection System Misoperation Data Collection.*[3]

The studies and analyses showing the effectiveness of the UVLS Program can be similar to what is required in Requirements R1 and R3, but should include a clear link between the evaluation of effectiveness (in studies using simulations) and the analysis of the event (with measurements and event data) that actually occurred. For example, differences between the expected and actual system behavior for the event of interest should be discussed and modeling assumptions should be evaluated. Important discrepancies between the simulations and the actual event should be investigated.

Considering the importance of an event that involves the operation of a UVLS Program, the 12-calendar-month period provides adequate time to analyze the event and perform an assessment while identifying deficiencies within a reasonable time. This time period is also required in PRC-006-1.

Guidelines for Requirement R5

Requirement R5 promotes the prudent correction of an identified problem during the assessment of a UVLS Program. Per Requirements R3 and R4, an assessment of an active UVLS Program is triggered:

- Within 12 calendar months of an event that resulted in a voltage excursion for which the program was designed to operate
- At least once every 60 calendar months. The default time frame of 60 calendar months or less between assessments has the intention to assure that the cumulative changes to the network and operating condition affecting the UVLS Program are evaluated

Since every UVLS is unique, if material changes are made to system topology or operating conditions, the Planning Coordinator or Transmission Planner will decide the degree to which the change in topology or operating condition becomes a material change sufficient to trigger an assessment of the existing UVLS Program.

A CAP is a list of actions and an associated timetable for implementation to remedy a specific problem. It is a proven tool for resolving operational problems. Per Requirement R5, the Planning Coordinator or Transmission Planner is required to develop a CAP and provide it to UVLS entities to accomplish the purpose of this requirement, which is to prevent future deficiencies in the UVLS Program, thereby minimizing risk to the system. Determining the cause of the deficiency is essential in developing an effective CAP to avoid future re-occurrence of the same problem. A CAP can be revised if additional causes are found.

Based on industry experience and operational coordination timeframes, three calendar months from the date an assessment is completed is a reasonable time frame for development of a CAP, including time to consider alternative solutions and coordination of resources. The “within three

[3] Id.

calendar months" time frame is solely to develop a CAP, including its implementation schedule, and provide it to UVLS entities. It does not include the time needed for its implementation by UVLS entities. This implementation time frame is dictated within the CAP's associated timetable for implementation, and the execution of the CAP according to its schedule is required in Requirement R2.

Guidelines for Requirements R6–R8

An accurate UVLS Program database is necessary for the Planning Coordinator or Transmission Planner to perform system reliability assessment studies and event analysis studies. Without accurate data, there is a possibility that annual reliability assessment studies that are performed by the Planning Coordinator or Transmission Planner can lead to erroneous results and therefore impact reliability. Also, without the accurate data, it is very difficult for the Planning Coordinator or Transmission Planner to duplicate a UVLS event and determine the root cause of the problem.

To support a UVLS Program database, it is necessary for each UVLS entity to provide accurate data to its Planning Coordinator. Each UVLS entity will provide the data according to the specified format and schedule provided by the Planning Coordinator. This is required in order for the Planning Coordinator to maintain and support a comprehensive UVLS Program database. By having a comprehensive database, the Planning Coordinator can embark on a reliability assessment or event analysis/benchmarking studies, identify the issues with the UVLS Program, and develop Corrective Action Plans.

The UVLS Program database may include, but is not limited to the following:

- Owner and operator of the UVLS Program
- Size and location of customer load, or percent of connected load, to be interrupted
- Corresponding voltage set points and clearing times
- Time delay from initiation to trip signal
- Breaker operating times
- Any other schemes that are part of or impact the UVLS Programs, such as related generation protection, islanding schemes, automatic load restoration schemes, underfrequency load shedding (UFLS), and RAS

Additionally, the UVLS Program database is required to be updated annually (once every calendar year) by the Planning Coordinator. The intent here is for UVLS entities to review the data annually and provide changes to the Planning Coordinators so that Planning Coordinators can keep the databases current and accurate for performing event analysis and other assessments.

Finally, a Planning Coordinator is required to provide information to other Planning Coordinators and Transmission Planners within its Interconnection, and other functional entities with a reliability need, within 30 calendar days of receipt of a written request. Thirty calendar days was selected as the time frame as it is considered to be reasonable and well- accepted by the industry. Also, this requirement of sharing the database with applicable functional entities supports the directive provided by FERC that requires an integrated and coordinated approach to UVLS programs (Paragraph 1509 of FERC Order No. 693).

Frequently Asked Questions

To succinctly address common comment themes that require drafting team response on Project 2008-02 UVLS (proposed PRC-010-1), the drafting team provides the following discussion in the construct of an FAQ format.

Introduction

This Frequently Asked Questions (FAQ) document was created during the development of PRC-010-1 (*Undervoltage Load Shedding*)[4, 5] to succinctly address common comment themes with respect to the approach and intent of the Project 2008-02 Undervoltage Load Shedding (UVLS)[6] standard drafting team ("drafting team"). This FAQ document is the outcome of comments received during comment periods and multiple outreach sessions with industry. All comments submitted by industry during comment periods may be reviewed on the project page.

Subsequent to the adoption of PRC-010-1, the UVLS drafting team made minor revisions to the standard address the UVLS Misoperation identification and correction.[7] This FAQ document was amended to reflect up the approach and intent of the drafting team during the development of PRC-010-2 concerning Misoperation of UVLS equipment.

Purpose of Standard Revision

1) What is the basis for a revision of the existing UVLS standards?

The initial input into a revision of the existing UVLS standards is FERC Order No. 693,[8] Paragraph 1509, which directed the ERO to develop a modification of PRC-010-0 that "requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride through capabilities, and UFLS and UVLS programs." In addition, *The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*[9] ("August 14 Blackout Report") showed that proper coordination would have mitigated effects if UVLS was used as a tool.

[4] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-010-1&title=Undervoltage%20Load%20Shedding).

[5] Adopted by the NERC Board of Trustees on November 14, 2014.

[6] (http://www.nerc.com/pa/Stand/Pages/Project-2008-02-Undervoltage-Load-Shedding.aspx).

[7] Refer to Project 2010-05.1, which developed PRC-004-3 (Protection System Misoperation Identification and Correction) concurrently with the development of PRC-010-1. (http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx).

[8] (http://www.nerc.com/docs/docs/ferc/order_693.pdf).

[9] (http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf).

Additional inputs included 1) recommendations from the NERC System Protection and Control Subcommittee (SPCS) in its December 2010 *Technical Review of UVLS-Related Standards*[10] to combine the four existing UVLS standards, revise the applicability to entities responsible for UVLS program design, implementation, and coordination, specifically include a requirement for assessment of coordination between UVLS programs and all other protection systems, and differentiate post-event validation of UVLS program design from verifying correct operation of UVLS equipment; 2) the existing UVLS standards were not in the current results-based format; 3) the preceding revision of the underfrequency load shedding (UFLS) standards had similar types of requirements and had been completed under the construct of a consolidation; and 4) the Independent Expert Review Panel recommendations, which included an evaluation of the existing standards' applicability and level of specificity.

The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability. As part of the revision to address this, the drafting team also agreed that an evaluation and consolidation of the existing UVLS standards was necessary to meet current Reliability Standard development initiatives and to provide clear, comprehensive requirements to address the application and coordination of UVLS.

2) UVLS programs are not mandatory—is compliance for an optional tool necessary?

The drafting team asserts that a key takeaway from the August 14 Blackout Report is that coordination of UVLS with other protection systems could have mitigated the effects if UVLS was used as a tool. Although the use of UVLS is not mandatory, if it is determined that this system preservation measure is necessary to support reliability and a UVLS program is installed, the program needs to be properly coordinated, implemented, and assessed due to the inherent associated reliability risks. As such, there needs to be a level of performance required to properly protect system reliability. Of note, PRC-010-1 and PRC-010-2 apply to the defined term "UVLS Program," which limits the standard's applicability to only those undervoltage-based load shedding programs whose performance has an impact on system reliability.[11]

Coordination with Project 2009-03 Emergency Operations

3) EOP-003-2 has potential redundant requirements with proposed PRC-010-1—how is this being addressed?

As part of its five-year review, Project 2009-03 – Emergency Operations (EOP) identified EOP-003-2 (*Load Shedding Plans*),[12] Requirements R2, R4, and R7 as being more properly covered by Project 2008-02 – UVLS. Both projects were strategically coordinated to move in lockstep from a timing perspective to address these requirements. Project 2009-03 – EOP proposed to revise and

[10] (http://www.nerc.com/docs/pc/spctf/PRC-010_022%20Report_Approved_20101208.pdf).

[11] The term "UVLS Program" used herein was adopted by the NERC Board of Trustees on November 14, 2014.

[12] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-003-2&title=Load%20Shedding%20Plans).

consolidate EOP-001-2.1b (*Emergency Operations Planning*),[13] EOP-002-3 (Capacity and Energy Emergencies),[14] and EOP-003-2 to create EOP-011-1, will retire the noted EOP-003-2 requirements (among other revisions), and the Project 2008-02 – UVLS *Mapping Document* will show how PRC-010-1 encompasses the retired content accordingly. Slated to have aligning effective dates, both EOP-011-1 (*Emergency Operations*)[15] and PRC-010-1 will be posted and balloted separately but concurrently, so that industry stakeholders will be able to clearly evaluate the transition. Please see the posted Project 2008-02 UVLS Project Coordination Plan for more information.

"UVLS Program" Definition

4) Why is the introduction of the new defined term "UVLS Program" necessary?

The drafting team found it necessary to introduce the term "UVLS Program" for inclusion in the *Glossary of Terms Used in NERC Reliability Standards*[16] ("NERC Glossary") because different types of UVLS systems need to be treated appropriately with respect to reliability requirements. Therefore, the term establishes which UVLS systems PRC-010-1 will apply to an: "automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

The definition excludes locally-applied relays that are designed to protect a contained area or, in other words, are not designed to mitigate wide-area voltage collapse. This exclusion is not explicit in these terms in the enforceable language of the definition since the meaning and measurement of "local" or "wide-area" varies greatly on a continent-wide basis and could potentially be interpreted differently by auditors and the applicable functional entities. Therefore, the definition as written is meant to provide flexibility for the Planning Coordinator or Transmission Planner to determine if a UVLS system falls under the defined term with respect to its impact on the reliability of the BES (voltage instability, voltage collapse, or Cascading). To further support the intended exclusion, further discussion and an example are provided on in the PRC-010-1 and PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition."

The definition does explicitly note that the term excludes centrally controlled undervoltage-based load shedding. This type of load shedding is excluded because the drafting team asserts that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with those of a Special Protection System (SPS) or Remedial Action Scheme (RAS) and should therefore be subject to SPS or RAS-related Reliability Standards. See PRC-010-1 and

13 (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-001-2.1b&title=Emergency%20Operations%20Planning).
14 (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3&title=Capacity%20and%20Energy%20Emergencies).
15 (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-011-1&title=Emergency%20Operations).
16 (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf).

PRC-010-2 Guidelines and Technical Basis section under the heading "Guidelines for UVLS Program Definition" for further discussion.

5) If the definition excludes certain types of UVLS, does this preclude an "integrated" approach (FERC Order No. 693, Paragraph 1509)?

The defined term "UVLS Program" clarifies which UVLS systems are subject to the requirements in PRC-010-1 and PRC-010-2. The resulting exclusions from these versions of the standard do not preclude an "integrated" approach because the standard requires that an entity coordinate with all other protection and control systems as necessary, which may include other types of UVLS (i.e., locally-applied UVLS relays and centrally controlled undervoltage-based load shedding).

6) Where will centrally controlled undervoltage-based load shedding be covered?

As explained immediately above, the Requirements of PRC-010-1 and PRC-010-2 are applicable to the proposed NERC Glossary term "UVLS Program," which excludes centrally controlled undervoltage-based load shedding because its design and characteristics are commensurate with those of an SPS or RAS. However, the NERC Glossary during the development of PRC-010-1 definition of "Special Protection System" excluded UVLS. Therefore, the work under Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems) combined the NERC Glossary definition of "Special Protection System" into the single term "Remedial Action Scheme."[17] The definition revisions specifically excluded UVLS Programs, therefore including centrally controlled undervoltage-based shedding.

Consequently, the introduction of the term "UVLS Program" and the conforming revision to the term "Remedial Action Scheme" explicitly clarifies that RAS-related standards are applicable to centrally controlled undervoltage-based load shedding. The implementation plan for the revised definition of "Remedial Action Scheme" will address entities that will have newly identified RAS resulting from the application of the defined term.

Similar to the coordination effort with Project 2009-03 – EOP explained above, Project 2008-02 – UVLS and Project 2010-05.2 – SPS were coordinated to ensure that the effective dates of the adopted definitions of "Remedial Action Scheme" and "UVLS Program," the PRC-010-1 and PRC-010-1 Reliability Standards, and all associated retirements align.

7) Is the term "UVLS Program" inclusive of a collection of independent UVLS relays?

No; multiple independent relays do not constitute a program. While the definition stipulates that a UVLS Program consists of distributed relays and controls, the definition specifies that it must be "[a]n automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System(BES), leading to voltage

[17] Adopted by the NERC Board of Trustees on November 14, 2014.

instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included."

Applicability

8) What is meant by the phrase "Planning Coordinator or Transmission Planner"?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs. The phrase "Planning Coordinator or Transmission Planner" provides the flexibility for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity. In addition, the requirements containing this phrase have specific language to qualify the responsible entity. For example, Requirement R1 states: "Each Planning Coordinator or Transmission Planner *that is developing* a UVLS Program shall . . ." This language provides clarity that the applicable entity would be the one that is developing the program.

9) Why is the Transmission Operator not included?

While the Transmission Operator may be involved with UVLS Program activities, the drafting team did not identify any required performance for the Transmission Operator that was necessary to capture within PRC-010-1 and PRC-010-2, since the Transmission Operator does not have the resources necessary to implement program specifications. If responsibilities are delegated to the Transmission Operator by the Transmission Owner, the Transmission Owner is still the accountable party.

To the extent that the Transmission Operator is required to have knowledge of system relays and protection systems, the drafting team notes that this requirement is covered under PRC-001-1.1 (*System Protection Coordination*),[18] Requirement R1. It is also noted that manual load shedding, for which the Transmission Operator is responsible, is not in the purview of PRC-010-1 and PRC-010-2, as it is covered under current EOP-003-2 and will subsequently be covered by proposed EOP-011-1 (see Project 2009-03 – Emergency Operations).

10) What about UVLS schemes owned by Transmission Owners, Distribution Providers, or Transmission Operators that are not required by the planner?

The PRC-010-1 and PRC-010-2 Reliability Standards are applicable to the term "UVLS Program." The drafting team notes that, by its defining attributes, a UVLS Program would be required and developed by a Planning Coordinator or Transmission Planner. The nature of a UVLS scheme developed or required by a Distribution Provider, Transmission Operator, or Transmission Owner

[18] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-001-1.1&title=System%20Protection%20 Coordination.

would not meet the attributes of the defined term and would therefore not have the design and characteristics necessary to be subject to the requirements of PRC-010-1 and PRC-010-2.

Requirements R1, R3, R4, and R5

11) What is required to evaluate the coordination referenced in Requirement R1, part 1.2?

Requirement R1 requires each Planning Coordinator or Transmission Planner that develops a UVLS Program to evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage issues that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. As such, the requirement is meant to provide flexibility for an entity to make the proper determinations, including the considerations for coordination, with respect to program effectiveness based on system characteristics. For further guidance on and examples of coordination considerations, please see the portion of the Guidelines and Technical Basis section under the Requirement R1 heading.

12) Requirements R1, R3, and R4 seem to all require evaluations of program effectiveness—how are they different?

Requirements R1, R3, and R4 do require evaluations of program effectiveness, but they are each at distinct points in time.

Requirement R1 requires evaluation of program effectiveness (by way of the qualifying parts) at the onset of program development, or during the initial planning stage, prior to implementation. Requirement R3 requires the same objectives of an evaluation of effectiveness, but at the point of a mandatory periodic review (at least once every 60 calendar months). Requirement R4 addresses the performance of a UVLS Program after an event (for applicable voltage excursion) to evaluate whether the UVLS Program resolved the undervoltage issues associated with the event.

It is noted that, because of the separate activities of each requirement, UVLS Program deficiencies found as a result of the assessments performed in Requirement R3 or R4 would not be violations of Requirement R1.

13) Requirement R4 would require the Planning Coordinator or Transmission Planner to review all voltage excursions—isn't this unduly burdensome?

While Requirement R4 essentially requires the Planning Coordinator or Transmission Planner to review all voltage excursions to see if they fall below the initializing set points of the UVLS Program, the drafting team contends that it will be clearly evident if voltage falls below the UVLS threshold because either a) UVLS devices will operate; or b) the system will experience the adverse conditions the UVLS Program was installed to mitigate.

In addition, the drafting team acknowledges that the Planning Coordinator or Transmission Planner may not have the ability to know when voltage excursions are occurring since they are not operating entities. However, a process for the Transmission Operator, Transmission Owner, or Distribution Provider to notify the Transmission Planner or Planning Coordinator of such voltage excursion events is consistent with standard utility practice.

14) PRC-022-1 required the analysis of UVLS Misoperations. How is this addressed in PRC-010-1?

One of the recommendations in the SPCS report was to clearly differentiate between the post-event process of validating the effectiveness of the UVLS program design, its coordination with other protection and control systems, and the potential need to modify the program design (activities addressed in PRC-010-1) and the process of verifying correct operation of UVLS equipment. Because PRC-010-1 was not specific concerning the Misoperation of UVLS equipment, the drafting team made a subsequent revision creating PRC-010-2. Version two (PRC-010-2) now requires that the assessment according to Requirement R4 include the performance (i.e., operation or non-operation) of the UVLS Program equipment.

Relative to the assessment, Requirement R5 requires that a Corrective Action Plan be developed to address any identified deficiencies. This structure ensures that UVLS Program equipment is assessed to identify any Misoperation which could affect BES reliability. Although, the UVLS drafting team maintained during development of PRC-010-1 that verifying correct operation of UVLS equipment should be addressed in PRC-004, the drafting team included UVLS that is intended to trip one or more BES Elements in the proposed PRC-004-5.

Requirements R6, R7, and R8

15) Do Requirements R6, R7, and R8 overlap with the requirements of MOD-032-1?

While both MOD-032-1 (*Data for Power System Modeling and Analysis*)[19] and Requirements R6, R7, and R8 of PRC-010-1 and PRC-010-2 address data requirements, MOD-032-1 establishes overarching modeling data requirements with respect to consistency in format and reporting procedures, whereas the PRC-010-1 and PRC-010-2 requirements address the need to maintain and share data and databases for the purposes of studies for use in event analyses for UVLS Programs specifically. While Reliability Standards in general may have overlap in this manner, the activities in these requirements remain distinctly different.

[19] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis).

16) Requirements R6, R7, and R8 appear to be administrative — doesn't this conflict with Paragraph 81 criteria?[20]

Proper maintenance and timely sharing of UVLS Program data as required by Requirements R6, R7, and R8 is necessary to inform the Planning Coordinator or Transmission Planner's studies and analyses. While administrative tasks are required, the tasks have a core reliability-based need.

In addition, Requirements R6, R7, and R8 were written to emulate FERC-approved PRC-006-2 (*Automatic Underfrequency Load Shedding*) [21, 22] data requirements. While some of these analogous requirements in PRC-006-2 are listed as candidates for Phase 2 of the Paragraph 81 project, they are not yet approved as meeting the criteria; furthermore, the Independent Expert Review Panel has recommended that these Paragraph 81 candidates not be included for deletion, citing that "there should be a clear expectation for Planning Coordinators to share data necessary to determine their UFLS program parameters."

Rationale

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

Rationale for Applicability

This standard is applicable to Planning Coordinators and Transmission Planners that have or are developing a UVLS Program, and to Distribution Providers and Transmission Owners responsible for the ownership, operation, or control of UVLS equipment as required by the UVLS Program established by the Transmission Planner or Planning Coordinator. These Distribution Providers and Transmission Owners are referred to as UVLS entities for the purpose of this standard.

The applicability includes both the Planning Coordinator and Transmission Planner because either may be responsible for designing and coordinating the program based on agreements, memorandums of understanding, or tariffs.

The phrase "Planning Coordinator or Transmission Planner" provides the latitude for applicability to the entity that will perform the action. The expectation is not that both parties will perform the action, but rather that the Planning Coordinator and Transmission Planner will engage in discussion to determine the appropriate responsible entity.

Rationale for R1

In Paragraph 1509 from Order No. 693, FERC directed NERC to require an integrated and coordinated approach to all protection systems. The drafting team agrees that a lack of coordination among protection systems is a key risk to reliability, and that each Planning

[20] Refer to Standards Independent Expert Review Project (IERP). (http://www.nerc.com/pa/Stand/Standard%20 Development%20Plan/Standards_Independent_Experts_Review_Project_Report-SOTC_and_Board.pdf).

[21] (http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-006-2&title=Automatic%20Underfrequency %20Load%20Shedding).

[22] Adopted by the NERC Board of Trustees on November 14, 2014.

Coordinator or Transmission Planner that develops a UVLS Program should evaluate the program's viability and effectiveness prior to implementation. This evaluation should include studies and analyses used when developing the program that show implementation of the program resolves the identified undervoltage conditions that led to its design. These studies and analyses should also show that the UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems. Though presented as separate items, the drafting team recognizes that the studies that show coordination considerations and that the program addresses undervoltage issues may be interrelated and presented as one comprehensive analysis.

In addition, Requirement R1 also requires the Planning Coordinator or Transmission Planner to provide the UVLS Program's specifications and implementation schedule to applicable UVLS entities to implement the program. It is noted that studies to evaluate the effectiveness of the program should be completed prior to providing the specifications and schedule.

Rationale for R2

UVLS entities must implement a UVLS Program or address any necessary corrective actions for a UVLS Program according to the specifications and schedule provided by the Planning Coordinator or Transmission Planner. If UVLS entities do not implement the UVLS Program according to the specifications and schedule provided, the UVLS Program may not be effective and may not achieve its intended goal.

Rationale for R3

A periodic comprehensive assessment (detailed analysis) should be conducted to identify and catalogue the accumulated effects of minor changes to the system that have occurred since the last assessment was completed, and should include an evaluation of each UVLS Program to ensure the continued integration through coordination. This comprehensive assessment supplements the NERC Reliability Standard TPL-001-4 annual assessment requirement to evaluate the impact of protection systems.

Based on the drafting team's knowledge and experience, and in keeping with time frames contained in similar requirements from other PRC Reliability Standards, 60 calendar months was determined to be the maximum amount of time allowable between assessments. Assessments will be performed sooner than the end of the 60-calendar month period if the Planning Coordinator or Transmission Planner determines that there are material changes to system topology or operating conditions that affect the performance of a UVLS Program. Note that the 60-calendar-month time frame would reset after each assessment.

Rationale for R4

A UVLS Program not functioning as expected during a voltage excursion event for which the UVLS Program was designed to operate presents a critical risk to system reliability. Therefore, a timely assessment to evaluate (1) whether the UVLS Program resolved the undervoltage issues and (2) the performance of the UVLS Program equipment associated with the applicable event is essential. The 12 calendar months (from the date of the event) provides adequate time to coordinate with other Planning Coordinators, Transmission Planners, Transmission Operators, and UVLS entities, simulate pre- and post-event conditions, and complete the performance assessment.

Rationale for R5

If program deficiencies are identified during an assessment performed in either Requirement R3 or R4, the Planning Coordinator or Transmission Planner must develop a Corrective Action Plan (CAP) to address the deficiencies. Based on the drafting team's knowledge and experience with UVLS studies, three calendar months was determined to provide a judicious balance between the reliability need to address deficiencies expeditiously and the time needed to consider potential solutions, coordinate resources, develop a CAP and implementation schedule, and provide the CAP and schedule to UVLS entities.

It is noted that the three-month time frame is only to develop the CAP and provide it to UVLS entities and does not encompass the time UVLS entities have to implement the CAP. Requirement R2 requires UVLS entities to execute the CAP according to the schedule provided by the Planning Coordinator or Transmission Planner.

Rationale for R6

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R6 supports this reliability need by requiring the Planning Coordinator to update its UVLS Program database at least once each calendar year.

Rationale for R7

Having accurate and current data is required for the Planning Coordinator to perform undervoltage studies and for use in event analyses. Requirement R7 supports this reliability need by requiring the UVLS entity to provide UVLS Program data in accordance with specified parameters.

Rationale for R8

Requirement R8 supports the integrated and coordinated approach to UVLS programs directed by Paragraph 1509 of Order No. 693 by requiring that UVLS Program data be shared with neighboring Planning Coordinators and Transmission Planners within a reasonable time period. Requests for the database should also be fulfilled for those functional entities that have a reliability need for the data (such as the Transmission Operators that develop System Operating Limits and Reliability Coordinators that develop Interconnection Reliability Operating Limits).

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee authorized Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal comment period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017
45-day formal comment period with additional ballot	February 23 – April 23, 2018
45-day formal comment period with additional ballot	July 30 – September 14, 2018

Anticipated Actions	Date
10-day final ballot	October 2018
Board adoption	November 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

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

2. **Number:** **TPL-001-~~4~~5.1**

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

   - Planning Coordinator.
   - Transmission Planner.

5. **~~Effective Date:~~ See Implementation Plan.**~~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 and Measures

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~~032 standard, 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.**~~**1.1.2.** New planned Facilities and changes to existing Facilities.

~~**1.1.4.**~~**1.1.3.** Real and reactive Load forecasts.

~~**1.1.5.**~~**1.1.4.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.6.**~~**1.1.5.** Resources (supply or demand side) required for Load.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within ~~their~~ its respective area, using data consistent with MOD-~~010 and MOD-012~~032, 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.

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.**~~**2.1.3.** 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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~~assessed. Based upon this assessment, an~~The~~ ~~studies~~ analysis 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

2.4.5. 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 assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

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~~Remedial Action Schemes.
- 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.

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.

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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 ~~&~~and 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.~~

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.

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~~ Remedial Action Scheme 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. 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.

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.~~

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.

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]*

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.

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]*

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.

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]*

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.

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.

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.

C. ~~Compliance~~

~~1. Compliance Monitoring Process~~

~~**1.1. Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.~~

~~**1.2. Evidence Retention:** The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.~~

~~The applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

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

~~**1.3. Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.~~

~~**1.4. Compliance Monitoring Period and Reset Timeframe:**~~

~~Not applicable.~~

~~**1.5. Compliance Monitoring and Enforcement Processes:**~~

- ~~Compliance Audits~~
- ~~Self-Certifications~~
- ~~Spot Checks~~
- ~~Compliance Violation Investigations~~
- ~~Self-Report~~
- ~~Complaints~~

~~**1.6. Additional Compliance Information**~~

~~None.~~

~~Violation Severity Levels~~

~~R #~~	~~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~~5~~.~~	~~The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.~~~~6~~5~~.~~	~~The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.~~~~6~~5~~.~~	~~The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.~~~~6~~5~~.~~ ~~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~~032 ~~standard~~~~s 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~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~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.~~ ~~OR~~ ~~The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.~~	~~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 Table 1.~~ ~~OR~~ ~~The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.~~	~~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.~~ ~~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~~	~~The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements~~	~~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~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~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.~~	~~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 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.~~
~~**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.~~

~~R #~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~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.~~

~~B.~~D. Regional Variances

None.

E. Associated Documents

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.	

Version	Date	Action	Change Tracking
		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.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

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

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~component of a Protection System[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.	**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 fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

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.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~e.~~i. 3Ø internal breaker fault. ~~f.~~j. 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.

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
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~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions~~ or types: pilot (#85), distance (#21), differential (#87), current (#50, 51,~~, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and ~~67),~~reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67), and tripping (#86, & 94).~~and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment 1

I. 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

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

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.**~~**M1.** ~~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.**~~**M1.** ~~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.**~~**M1.** ~~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.**~~**M1.** ~~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.~~

~~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.~~

BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

Appendix B

NERC Glossary of Terms used in Reliability Standards
Updated October 8, 2020

Glossary of Terms Used in NERC Reliability Standards

Updated October 8, 2020

This Glossary lists each term that was defined for use in one or more of NERC's continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through October 8, 2020.

This reference is divided into four sections, and each section is organized in alphabetical order.

Subject to Enforcement
Pending Enforcement
Retired Terms
Regional Definitions

The first three sections identify all terms that have been adopted by the NERC Board of Trustees for use in continent-wide standards; the Regional definitions section identifies all terms that have been adopted by the NERC Board of Trustees for use in regional standards.

Most of the terms identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to this glossary following board adoption, with the "FERC effective" date added following a final Order approving the definition.

Any comments regarding this glossary should be reported to the NERC Help Desk at https://support.nerc.net/. Select "Standards" from the Applications drop down menu and "Other" from the Standards Subcategories drop down menu.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Actual Frequency (F_A)	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The Interconnection frequency measured in Hertz (Hz).
Actual Net Interchange (NI_A)	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The algebraic sum of actual megawatt transfers across all Tie Lines, including Pseudo-Ties, to and from all Adjacent Balancing Authority areas within the same Interconnection. Actual megawatt transfers on asynchronous DC tie lines that are directly connected to another Interconnection are excluded from Actual Net Interchange.
Adequacy	Version 0 Reliability Standards		2/8/2005	3/16/2007		The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority whose Balancing Authority Area is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact	Coordinate Operations		2/7/2006	3/16/2007		The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
After the Fact	Project 2007-14	ATF	10/29/2008	12/17/2009		A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement	Version 0 Reliability Standards		2/8/2005	3/16/2007		A contract or arrangement, either written or verbal and sometimes enforceable by law.
Alternative Interpersonal Communication	Project 2006-06		11/7/2012	4/16/2015	10/1/2015	Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation.
Altitude Correction Factor	Project 2007-07		2/7/2006	3/16/2007		A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter	Version 0 Reliability Standards		2/8/2005	3/16/2007		An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	Version 0 Reliability Standards	ACE	12/19/2012	10/16/2013	4/1/2014	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.
Area Interchange Methodology	Project 2006-07		8/22/2008	11/24/2009		The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.
Arranged Interchange	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	The state where a Request for Interchange (initial or revised) has been submitted for approval.
Attaining Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority bringing generation or load into its effective control boundaries through a Dynamic Transfer from the Native Balancing Authority.
Automatic Generation Control	Project 2010-14.2.1. Phase 2	AGC	2/11/2016	9/20/2017	1/1/2019	A process designed and used to adjust a Balancing Authority Areas' Demand and resources to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

SUBJECT TO ENFORCEMENT

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Automatic Time Error Correction (I_{ATEC})	[Project 2010-14.2.1. Phase 2]()		2/11/2016		7/1/2016	• Y = Bi / BS. • H = Number of hours used to payback primary inadvertent interchange energy. The value of H is set to 3. B_i = Frequency Bias Setting for the Balancing Authority Area (MW / 0.1 Hz). • B_S = Sum of the minimum Frequency Bias Settings for the Interconnection (MW / 0.1 Hz). Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - Bi * ΔTE/6) • II_{actual} is the hourly Inadvertent Interchange for the last hour. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor,where: ΔTE = $TE_{end\ hour}$ – $TE_{begin\ hour}$ – TD_{adj} – (t)*(TE_{offset})
Automatic Time Error Correction (I_{ATEC})	[Project 2010-14.2.1. Phase 2]()		2/11/2016		7/1/2016	• TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection time monitor control center clocks. • t is the number of minutes of manual Time Error Correction that occurred during the hour. • TE_{offset} is 0.000 or +0.020 or -0.020. • PII_{accum} is the Balancing Authority Area's accumulated PIIhourly in MWh. An On-Peak and Off-Peak accumulation accounting is required, where: $PII_{accum}^{on/offpeak} = last\ period's\ PII_{accum}^{on/offpeak} + PII_{hourly}$
Automatic Time Error Correction (I_{ATEC}) ***continued below...***	[Project 2010-14.2.1. Phase 2]()		2/11/2016		7/1/2016	The addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection. [illegible] hen operating in Automatic Time error correction Mode.The absolute value of I_{ATEC} shall not exceed L_{max}. I_{ATEC} shall be zero when operating in any other AGC mode. • L_{max} is the maximum value allowed for I_{ATEC} set by each BA between 0.2*|B_i| and L10, 0.2*|B_i|≤ L_{max} ≤ L10 . • L_{10} =1.65 • ε10 is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute a[illegible] $\varepsilon_{10}\sqrt{(-10B_i)(-10B_S)}$ or based on frequency performance over a given year. The bound, ε 10, is the same for every Balancing Authority Area within an Interconnection.
Available Flowgate Capability	[Project 2006-07]()	AFC	8/22/2008	11/24/2009		A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability	[Project 2006-07]()	ATC	8/22/2008	11/24/2009		A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Available Transfer Capability Implementation Document	[Project 2006-07]()	ATCID	8/22/2008	11/24/2009		A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Balancing Authority	Project 2010-14.2.1. Phase 2		2/11/2016	9/20/2017	1/1/2019	The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area	Version 0 Reliability Standards		2/8/2005	3/16/2007		The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Balancing Contingency Event	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less. A. Sudden loss of generation: a. Due to i. unit tripping, or ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or iii. sudden unplanned outage of transmission Facility; b. And, that causes an unexpected change to the responsible entity's ACE; B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.
Base Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		The minimum amount of electric power delivered or required over a given period at a constant rate.
BES Cyber Asset	Project 2014-02	BCA	2/12/2015	1/21/2016	7/1/2016	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.
BES Cyber System	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
BES Cyber System Information	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Blackstart Resource	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch	Project 2006-07		8/22/2008	11/24/2009		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).
Bulk Electric System **(continued below)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. **Inclusions:** • I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3. • I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with: a) Gross individual nameplate rating greater than 20 MVA. Or, b) Gross plant/facility aggregate nameplate rating greater than 75 MVA. • I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.
Bulk Electric System **(continued below)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	• I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above. • I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	**Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion. Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	• **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	• **E3** - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following: a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating); b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
Bulk Electric System **(continued)**	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Imple-mentation Plan for Phase 2 Compliance obligations.)	c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • E4 – Reactive Power devices installed for the sole benefit of a retail customer(s). Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Bulk-Power System	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	Bulk-Power System: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Note that the terms “Bulk-Power System” or “Bulk Power System” shall have the same meaning.)
Burden	Version 0 Reliability Standards		2/8/2005	3/16/2007		Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Bus-tie Breaker	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	A circuit breaker that is positioned to connect two individual substation bus configurations.
Capacity Benefit Margin	Version 0 Reliability Standards	CBM	2/8/2005	3/16/2007		The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider’s system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Capacity Benefit Margin Implementation Document	Project 2006-07	CBMID	11/13/2008	11/24/2009		A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency	Version 0 Reliability Standards		2/8/2005	3/16/2007		A capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
CIP Exceptional Circumstance	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
CIP Senior Manager	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC CIP Standards, CIP-002 through CIP-011.
Clock Hour	Version 0 Reliability Standards		2/8/2005	3/16/2007		The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
Cogeneration	Version 0 Reliability Standards		2/8/2005	3/16/2007		Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
Compliance Monitor	Version 0 Reliability Standards		2/8/2005	3/16/2007		The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Composite Confirmed Interchange	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	The energy profile (including non-default ramp) throughout a given time period, based on the aggregate of all Confirmed Interchange occurring in that time period.
Composite Protection System	2010-05.1		8/14/2014	5/13/2015	7/1/2016	The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.
Confirmed Interchange	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	The state where no party has denied and all required parties have approved the Arranged Interchange.
Congestion Management Report	Version 0 Reliability Standards		2/8/2005	3/16/2007		A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	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.
Constrained Facility	Version 0 Reliability Standards		2/8/2005	3/16/2007		A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contact Path	Version 0 Reliability Standards		2/8/2005	3/16/2007		An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Contingency	Version 0 Reliability Standards		2/8/2005	3/16/2007		The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Event Recovery Period	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event, and extends for fifteen minutes thereafter.
Contingency Reserve	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority: • is experiencing a Reliability Coordinator declared Energy Emergency Alert level, and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan. • is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
Contingency Reserve Restoration Period	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.
Control Center	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
Control Performance Standard	Version 0 Reliability Standards	CPS	2/8/2005	3/16/2007		The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Corrective Action Plan	Phase III-IV Planning Standards - Archive		2/7/2006	3/16/2007		A list of actions and an associated timetable for implementation to remedy a specific problem.
Cranking Path	Phase III-IV Planning Standards - Archive		5/2/2006	3/16/2007		A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Curtailment	Version 0 Reliability Standards		2/8/2005	3/16/2007		A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold	Version 0 Reliability Standards		2/8/2005	3/16/2007		The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.
Cyber Assets	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.
Delayed Fault Clearing	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		11/1/2006	12/27/2007		Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
Demand	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Demand-Side Management	Project 2010-04	DSM	5/6/2014	2/19/2015	7/1/2016	All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.
Dial-up Connectivity	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
Direct Control Load Management	Project 2008-06	DCLM	2/8/2005	3/16/2007		Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
Dispatch Order	Project 2006-07		8/22/2008	11/24/2009		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.
Dispersed Load by Substations	Version 0 Reliability Standards		2/8/2005	3/16/2007		Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor	Version 0 Reliability Standards	DF	2/8/2005	3/16/2007		The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Distribution Provider	Project 2015-04	DP	11/5/2015	1/21/2016	7/1/2016	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
Disturbance	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard	Version 0 Reliability Standards	DCS	2/8/2005	3/16/2007		The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Monitoring Equipment	Phase III-IV Planning Standards	DME	8/2/2006	3/16/2007		Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders* : • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions *Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.
Dynamic Interchange Schedule or Dynamic Schedule	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A time-varying energy transfer that is updated in Real-time and included in the Scheduled Net Interchange (NIS) term in the same manner as an Interchange Schedule in the affected Balancing Authorities' control ACE equations (or alternate control processes).
Dynamic Transfer	Version 0 Reliability Standards		2/8/2005	3/16/2007		The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.
Economic Dispatch	Version 0 Reliability Standards		2/8/2005	3/16/2007		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
Electrical Energy	Version 0 Reliability Standards		2/8/2005	3/16/2007		The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
Electronic Access Control or Monitoring Systems	Project 2008-06 Order 706	EACMS	11/26/2012	11/22/2013	7/1/2016	Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Systems.
Electronic Access Point	Project 2008-06 Order 706	EAP	11/26/2012	11/22/2013	7/1/2016	A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
Electronic Security Perimeter	Project 2008-06 Order 706	ESP	11/26/2012	11/22/2013	7/1/2016	The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
Element	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Emergency or BES Emergency	Version 0 Reliability Standards		2/8/2005	3/16/2007		Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.
Emergency Request for Interchange	Project 2007-14 Coordinate Interchange	Emergency RFI	10/29/2008	12/17/2009		Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
Energy Emergency	Version 0		11/13/2014	11/19/2015	4/1/2017	A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load obligations.
Equipment Rating	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		2/7/2006	3/16/2007		The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
Existing Transmission Commitments	Project 2006-07	ETC	8/22/2008	11/24/2009		Committed uses of a Transmission Service Provider's Transmission system considered when determining ATC or AFC.
External Routable Connectivity	Project 2008-06 Order 706		11/26/2012	11/22/2013	7/1/2016	The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.
Facility	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		2/7/2006	3/16/2007		A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)
Facility Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Fault	Version 0 Reliability Standards		2/8/2005	3/16/2007		An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk	Project 2007-07		2/7/2006	3/16/2007		The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand	Version 0 Reliability Standards		2/8/2005	3/16/2007		That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover	Project 2007-07		2/7/2006	3/16/2007		An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate	Project 2006-07		8/22/2008	11/24/2009		1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Flowgate Methodology	Version 0 Reliability Standards		8/22/2008	11/24/2009		The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
Forced Outage	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias	Version 0 Reliability Standards		2/8/2005	3/16/2007		A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.
Frequency Bias Setting	Project 2007-12		2/7/2013	1/16/2014	4/1/2015	A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems.
Frequency Deviation	Version 0 Reliability Standards		2/8/2005	3/16/2007		A change in Interconnection frequency.
Frequency Error	Version 0 Reliability Standards		2/8/2005	3/16/2007		The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation	Version 0 Reliability Standards		2/8/2005	3/16/2007		The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response	Version 0 Reliability Standards		2/8/2005	3/16/2007		(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Frequency Response Measure	Project 2007-12	FRM	2/7/2013	1/16/2014	4/1/2015	The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz.
Frequency Response Obligation	Project 2007-12	FRO	2/7/2013	1/16/2014	4/1/2015	The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.
Frequency Response Sharing Group	Project 2007-12	FRSG	2/7/2013	1/16/2014	4/1/2015	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Generation Capability Import Requirement	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	GCIR	11/13/2008	11/24/2009		The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
Generator Operator	Version 0 Reliability Standards	GOP	11/5/2015	1/21/2016	7/1/2016	The entity that operates generating Facility(ies) and performs the functions of supplying energy and Interconnected Operations Services.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Generator Owner	Version 0 Reliability Standards	GO	11/5/2015	1/21/2016	7/1/2016	Entity that owns and maintains generating Facility(ies).
Generator Shift Factor	Version 0 Reliability Standards	GSF	2/8/2005	3/16/2007		A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
Generator-to-Load Distribution Factor	Version 0 Reliability Standards	GLDF	2/8/2005	3/16/2007		The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	Project 2013-03 Geomagnetic Disturbance Mitigation	GMD	12/17/2014	9/22/2016	7/1/2017	Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.
Host Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Hourly Value	Version 0 Reliability Standards		2/8/2005	3/16/2007		Data measured on a Clock Hour basis.
Implemented Interchange	Coordinate Interchange		5/2/2006	3/16/2007		The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
Inadvertent Interchange	Version 0 Reliability Standards		2/8/2005	3/16/2007		The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. (IA – IS)
Independent Power Producer	Version 0 Reliability Standards	IPP	2/8/2005	3/16/2007		Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
Institute of Electrical and Electronics Engineers, Inc.	Project 2007-07	IEEE	2/7/2006	3/16/2007		
Interactive Remote Access	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.
Interchange	Coordinate Interchange		5/2/2006	3/16/2007		Energy transfers that cross Balancing Authority boundaries.
Interchange Authority	Project 2015-04	IA	11/5/2015	1/21/2016	7/1/2016	The responsible entity that authorizes the implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Interchange Distribution Calculator	Version 0 Reliability Standards		2/8/2005	3/16/2007		The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection.
Interchange Meter Error (I_{ME})	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	A term used in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components of the Reporting ACE calculation.
Interchange Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction	Version 0 Reliability Standards		2/8/2005	3/16/2007		An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag	Version 0 Reliability Standards		2/8/2005	3/16/2007		The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	A service (exclusive of basic energy and Transmission Services) that is required to support the Reliable Operation of interconnected Bulk Electric Systems.
Interconnection	Project 2015-04		11/5/2015	1/21/2016	7/1/2016	A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection Reliability Operating Limit	Determine Facility Ratings, Operating Limits, and Transfer Capabilities	IROL	11/1/2006	12/27/2007		A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.
Interconnection Reliability Operating Limit T_v	Determine Facility Ratings, Operating Limits, and Transfer Capabilities	IROL T_v	11/1/2006	12/27/2007		The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_v shall be less than or equal to 30 minutes.
Intermediate Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority on the scheduling path of an Interchange Transaction other than the Source Balancing Authority and Sink Balancing Authority.
Intermediate System	Project 2008-06		11/26/2012	11/22/2013	7/1/2016	A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Interpersonal Communication	Project 2006-06		11/7/2012	4/16/2015	10/1/2015	Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand	Version 0 Reliability Standards		11/1/2006	3/16/2007		Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.
Joint Control	Version 0 Reliability Standards		2/8/2005	3/16/2007		Automatic Generation Control of jointly owned units by two or more Balancing Authorities.
Limiting Element	Version 0 Reliability Standards		2/8/2005	3/16/2007		The element that is 1.)Either operating at its appropriate rating, or 2,) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		An end-use device or customer that receives power from the electric system.
Load Shift Factor	Version 0 Reliability Standards	LSF	2/8/2005	3/16/2007		A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
Load-Serving Entity	Project 2015-04	LSE	11/5/2015	1/21/2016	7/1/2016	Secures energy and Transmission Service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Long-Term Transmission Planning Horizon	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	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.
Market Flow	Project 2006-08 Reliability Coordination - Transmission Loading Relief		11/4/2010	4/21/2011		The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
Minimum Vegetation Clearance Distance	Project 2007-07	MVCD	11/3/2011	3/21/2013	7/1/2014	The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.
Misoperation	Project 2010-05.1		8/14/2014	5/13/2015	7/1/2016	The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation: **1. Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct. **2. Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct. **3. Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. (continued below...)
Misoperation (continued...)	Project 2010-05.1		8/14/2014	5/13/2015	7/1/2016	**4. Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. **5. Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element. **6. Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Most Severe Single Contingency	Project 2010-14.1 Phase 1	MSSC	11/5/2015	1/19/2017	1/1/2018	The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).
Native Balancing Authority	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	A Balancing Authority from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining Balancing Authority through a Dynamic Transfer.
Native Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon	Project 2010-10		1/24/2011	11/17/2011		The transmission planning period that covers Year One through five.
Net Actual Interchange	Version 0 Reliability Standards		2/8/2005	3/16/2007		The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load	Version 0 Reliability Standards		2/8/2005	3/16/2007		Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange	Version 0 Reliability Standards		2/8/2005	3/16/2007		The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.
Non-Consequential Load Loss	Project 2006-02		8/4/2011	10/17/2013	1/1/2015	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.
Non-Firm Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Clearing	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		11/1/2006	12/27/2007		A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Normal Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.
Nuclear Plant Generator Operator	Project 2009-08		5/2/2007	10/16/2008		Any Generator Operator or Generator Owner that is a Nuclear Plant Licensee responsible for operation of a nuclear facility licensed to produce commercial power.
Nuclear Plant Interface Requirements	Project 2009-08	NPIRs	5/2/2007	10/16/2008		The requirements based on NPLRs and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.
Nuclear Plant Licensing Requirements	Project 2009-08	NPLRs	5/2/2007	10/16/2008		Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for: 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.
Nuclear Plant Off-site Power Supply (Off-site Power)	Project 2009-08		5/2/2007	10/16/2008		The electric power supply provided from the electric system to the nuclear power plant distribution system as required per the nuclear power plant license.
Off-Peak	Version 0 Reliability Standards		2/8/2005	3/16/2007		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak	Version 0 Reliability Standards		2/8/2005	3/16/2007		Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service	Version 0 Reliability Standards	OASIS	2/8/2005	3/16/2007		An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff	Version 0 Reliability Standards	OATT	2/8/2005	3/16/2007		Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Instruction	Project 2007-02		5/6/2014	4/16/2015	7/1/2016	A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)
Operating Plan	Coordinate Operations		2/7/2006	3/16/2007		A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.
Operating Procedure	Coordinate Operations		2/7/2006	3/16/2007		A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process	Coordinate Operations		2/7/2006	3/16/2007		A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Operating Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve – Spinning	Version 0 Reliability Standards		2/8/2005	3/16/2007		The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve – Supplemental	Version 0 Reliability Standards		2/8/2005	3/16/2007		The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Voltage	Project 2007-07		2/7/2006	3/16/2007		The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean-square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis	Project 2014-03	OPA	11/13/2014	11/19/2015	1/1/2017	An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Operations Support Personnel	Project 2010-01		2/6/2014	6/19/2014	7/1/2016	Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,1 in direct support of Real-time operations of the Bulk Electric System.
Outage Transfer Distribution Factor	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	OTDF	8/22/2008	11/24/2009		In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.
Participation Factors	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand	Version 0 Reliability Standards		2/8/2005	3/16/2007		1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Performance-Reset Period	Determine Facility Ratings, Operating Limits, and Transfer Capabilities		2/7/2006	3/16/2007		The time period that the entity being assessed must operate without any violations to reset the level of non compliance to zero.
Physical Access Control Systems	Project 2008-06 Cyber Security Order 706	PACS	11/26/2012	11/22/2013	7/1/2016	Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter	Project 2008-06 Cyber Security Order 706	PSP	11/26/2012	11/22/2013	7/1/2016	The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.
Planning Assessment	Project 2006-02 Assess Transmission Future Needs and Develop Transmission Plans		8/4/2011	10/17/2013	1/1/2015	Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.
Planning Coordinator	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	PC	8/22/2008	11/24/2009		See Planning Authority.
Point of Delivery	Version 0 Reliability Standards	POD	2/8/2005	3/16/2007		A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	Project 2015-04 Alignment of Terms	POR	11/5/2015	1/21/2016	7/1/2016	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.
Point to Point Transmission Service	Version 0 Reliability Standards	PTP	2/8/2005	3/16/2007		The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Power Transfer Distribution Factor	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	PTDF	8/22/2008	11/24/2009		In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer
Pre-Reporting Contingency Event ACE Value	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	The average value of Reporting ACE, or Reserve Sharing Group Reporting ACE when applicable, in the 16-second interval immediately prior to the start of the Contingency Event Recovery Period based on EMS scan rate data.
Pro Forma Tariff	Version 0 Reliability Standards		2/8/2005	3/16/2007		Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets	Project 2014-02	PCA	2/12/2015	1/21/2016	7/1/2016	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Protection System	Project 2007-17 Protection System Maintenance and Testing		11/19/2010	2/3/2012	4/1/2013	Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.
Protection System Maintenance Program (PRC-005-6)	Project 2007-17.4 PRC-005 FERC Order No 803 Directive	PSMP	11/5/2015	12/18/2015	1/1/2016	An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities: • Verify — Determine that the Component is functioning correctly. • Monitor — Observe the routine in-service operation of the Component. • Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems. • Inspect — Examine for signs of Component failure, reduced performance or degradation. • Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie	Project 2010-14.2.1. Phase 2		2/11/2016	9/20/2017	1/1/2019	A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities' Reporting ACE equation (or alternate control processes).
Purchasing-Selling Entity	Version 0 Reliability Standards	PSE	2/8/2005	3/16/2007		The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Ramp Rate or Ramp	Version 0 Reliability Standards		2/8/2005	3/16/2007		(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
Rated Electrical Operating Conditions	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate
Rated System Path Methodology	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.
Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The operational limits of a transmission system element under a set of specified conditions.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Reactive Power	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The portion of electricity that supplies energy to the Load.
Real-time	Coordinate Operations		2/7/2006	3/16/2007		Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard.)
Real-time Assessment	Project 2014-03		11/13/2014	Revised definition. 11/19/2015	1/1/2017	An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)
Receiving Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Balancing Authority importing the Interchange.
Regional Reliability Organization	Version 0 Reliability Standards	RRO	2/8/2005	3/16/2007		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A member of the North American Electric Reliability Council. The Regional Reliability Organization can serve as the Compliance Monitor.
Regional Reliability Plan	Version 0 Reliability Standards		2/8/2005	3/16/2007		The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
Regulating Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulation Reserve Sharing Group	Project 2010-14.1 Phase 1		8/15/2013	4/16/2015	7/1/2016	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the Regulating Reserve required for all member Balancing Authorities to use in meeting applicable regulating standards.
Regulation Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Adjustment Arranged Interchange	Project 2008-12 Coordinate Interchange Standards		2/6/2014	6/30/2014	10/1/2014	A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes.
Reliability Adjustment RFI	Project 2007-14 Coordinate Interchange - Timing Table		10/29/2008	12/17/2009		Request to modify an Implemented Interchange Schedule for reliability purposes.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Reliability Coordinator	Project 2015-04 Alignment of Terms	RC	11/5/2015	1/21/2016	7/1/2016	The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area	Version 0 Reliability Standards		2/8/2005	3/16/2007		The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.
Reliability Coordinator Information System	Version 0 Reliability Standards	RCIS	2/8/2005	3/16/2007		The system that Reliability Coordinators use to post messages and share operating information in real time.
Reliability Standard	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	A requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk-Power System. The term includes requirements for the operation of existing Bulk-Power System facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for Reliable Operation of the Bulk-Power System, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Remedial Action Scheme	Project 2010-05.2	RAS	11/13/2014	11/19/2015	4/1/2017	A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: • Meet requirements identified in the NERC Reliability Standards; • Maintain Bulk Electric System (BES) stability; • Maintain acceptable BES voltages; • Maintain acceptable BES power flows; • Limit the impact of Cascading or extreme events. The following do not individually constitute a RAS: a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays c. Out-of-step tripping and power swing blocking d. Automatic reclosing schemes e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Remedial Action Scheme ***Continued***	Project 2010-05.2	RAS	11/13/2014	11/19/2015	4/1/2017	f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage) k. Automatic sequences that proceed when manually initiated solely by a System Operator l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
Remedial Action Scheme ***Continued***	Project 2010-05.2	RAS	11/13/2014	11/19/2015	4/1/2017	n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing
Removable Media	Project 2016-02 Modifications to CIP Standards		2/9/2017	4/19/2018	1/1/2020	Storage media that: 1. are not Cyber Assets, 2. are capable of transferring executable code, 3. can be used to store, copy, move, or access data, and 4. are directly connected for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • Protected Cyber Asset associated with high or medium impact BES Cyber Systems. Examples of Removable Media include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.
Reportable Balancing Contingency Event	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	Any Balancing Contingency Event occurring within a one-minute interval of an initial sudden decline in ACE based on EMS scan rate data that results in a loss of MW output less than or equal to the Most Severe Single Contingency, and greater than or equal to the lesser amount of: (i) 80% of the Most Severe Single Contingency, or (ii) the amount listed below for the applicable Interconnection. Prior to any given calendar quarter, the 80% threshold may be reduced by the responsible entity upon written notification to the Regional Entity. • Eastern Interconnection – 900 MW • Western Interconnection – 500 MW • ERCOT – 800 MW • Quebec – 500 MW

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Reportable Cyber Security Incident	Project 2008-06 Cyber Security Order 706 V5 CIP Standards		11/26/2012	11/22/2013	7/1/2016	A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.
Reportable Disturbance	Version 0 Reliability Standards		2/8/2005	3/16/2007		Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Reporting ACE	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC). Reporting ACE is calculated as follows: Reporting ACE = $(NI_A - NI_S) - 10B\ (F_A - FS) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: Reporting ACE = $(NI_A - NI_S) - 10B\ (F_A - F_S) - I_{ME} + I_{ATEC}$ Where: • NI_A = Actual Net Interchange. • NI_S = Scheduled Net Interchange. • B = Frequency Bias Setting. • F_A = Actual Frequency. • F_S = Scheduled Frequency. • I_{ME} = Interchange Meter Error. • I_{ATEC} = Automatic Time Error Correction.
Reporting ACE (continued)	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	All NERC Interconnections operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation: 1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is the same as total Interconnection generation, load, and loss; 2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times; 3. The use of a common Scheduled Frequency F_S for all BAAs at all times; and, 4. Excludes metering or computational errors. (The inclusion and use of the I_{ME} term corrects for known metering or computational errors.)
Request for Interchange	Project 2008-12 Coordinate Interchange	RFI	2/6/2014	6/30/2014	10/1/2014	A collection of data as defined in the NAESB Business Practice Standards submitted for the purpose of implementing bilateral Interchange between Balancing Authorities or an energy transfer within a single Balancing Authority.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Reserve Sharing Group	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.
Reserve Sharing Group Reporting ACE	Project 2010-14.1 Phase 1		11/5/2015	1/19/2017	1/1/2018	At any given time of measurement for the applicable Reserve Sharing Group (RSG), the algebraic sum of the ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the RSG at the time of measurement.
Resource Planner	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.
Response Rate	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way	Project 2010-07	ROW	5/9/2012	3/21/2013	7/1/2014	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the applicable Transmission Owner's or applicable Generator Owner's legal rights but may be less based on the aforementioned criteria.
Scenario	Coordinate Operations		2/7/2006	3/16/2007		Possible event.
Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency	Version 0 Reliability Standards		2/8/2005	3/16/2007		60.0 Hertz, except during a time correction.
Scheduled Net Interchange (NI_S)	Project 2010-14.2.1 Phase 2		2/11/2016		7/1/2016	The algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, to and from all Adjacent Balancing Authority areas within the same Interconnection, including the effect of scheduled ramps. Scheduled megawatt transfers on asynchronous DC tie lines directly connected to another Interconnection are excluded from Scheduled Net Interchange.
Scheduling Entity	Version 0 Reliability Standards		2/8/2005	3/16/2007		An entity responsible for approving and implementing Interchange Schedules.
Scheduling Path	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		The Balancing Authority exporting the Interchange.
Sink Balancing Authority	Project 2008-12 Coordinate Interchange Standards		2/6/2014	6/30/2014	10/1/2014	The Balancing Authority in which the load (sink) is located for an Interchange Transaction and any resulting Interchange Schedule.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Source Balancing Authority	Project 2008-12 Coordinate Interchange Standards		2/6/2014	6/30/2014	10/1/2014	The Balancing Authority in which the generation (source) is located for an Interchange Transaction and for any resulting Interchange Schedule.
Special Protection System (Remedial Action Scheme)	Project 2010-05.2	SPS	5/5/2016	6/23/2016	4/1/2017	See "Remedial Action Scheme"
Spinning Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		Unloaded generation that is synchronized and ready to serve additional demand.
Stability	Version 0 Reliability Standards		2/8/2005	3/16/2007		The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
Stability Limit	Version 0 Reliability Standards		2/8/2005	3/16/2007		The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Supervisory Control and Data Acquisition	Version 0 Reliability Standards	SCADA	2/8/2005	3/16/2007		A system of remote control and telemetry used to monitor and control the transmission system.
Supplemental Regulation Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
Surge	Version 0 Reliability Standards		2/8/2005	3/16/2007		A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System	Version 0 Reliability Standards		2/8/2005	3/16/2007		A combination of generation, transmission, and distribution components.
System Operating Limit	Project 2015-04 Alignment of Terms	SOL	11/5/2015	1/21/2016	7/1/2016	The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post- Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability) • system voltage limits (applicable pre- and post-Contingency voltage limits)
System Operator	Project 2010-01 Training		2/6/2014	6/19/2014	7/1/2016	An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time.
Telemetering	Version 0 Reliability Standards		2/8/2005	3/16/2007		The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Thermal Rating	Version 0 Reliability Standards		2/8/2005	3/16/2007		The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line	Version 0 Reliability Standards		2/8/2005	3/16/2007		A circuit connecting two Balancing Authority Areas.
Tie Line Bias	Version 0 Reliability Standards		2/8/2005	3/16/2007		A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Time Error	Version 0 Reliability Standards		2/8/2005	3/16/2007		The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction	Version 0 Reliability Standards		2/8/2005	3/16/2007		An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
TLR (Transmission Loading Relief) Log (NERC added the spelled out term for TLR Log for clarification purposes.)	Version 0 Reliability Standards		2/8/2005	3/16/2007		Report required to be filed after every TLR Level 2 or higher in a specified format. The NERC IDC prepares the report for review by the issuing Reliability Coordinator. After approval by the issuing Reliability Coordinator, the report is electronically filed in a public area of the NERC Web site.
Total Flowgate Capability	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions	TFC	8/22/2008	11/24/2009		The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
Total Internal Demand	Project 2010-04 Demand Data (MOD C)		5/6/2014	2/19/2015	7/1/2016	The Demand of a metered system, which includes the Firm Demand, plus any controllable and dispatchable DSM Load and the Load due to the energy losses incurred within the boundary of the metered system.
Total Transfer Capability	Version 0 Reliability Standards	TTC	2/8/2005	3/16/2007		The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transaction	Version 0 Reliability Standards		2/8/2005	3/16/2007		See Interchange Transaction.
Transfer Capability	Version 0 Reliability Standards		2/8/2005	3/16/2007		The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g* enerally equal to the transfer capability from "Area B" to "Area A."
Transfer Distribution Factor	Version 0 Reliability Standards		2/8/2005	3/16/2007		See Distribution Factor.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Transient Cyber Asset	Project 2016-02 Modifications to CIP Standards	TCA	2/9/2017	4/19/2018	1/1/2020	A Cyber Asset that is: 1. capable of transmitting or transferring executable code, 2. not included in a BES Cyber System, 3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and 4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a: • BES Cyber Asset, • network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or • PCA associated with high or medium impact BES Cyber Systems. Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Transmission	Version 0 Reliability Standards		2/8/2005	3/16/2007		An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.
Transmission Constraint	Version 0 Reliability Standards		2/8/2005	3/16/2007		A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	1. Any eligible customer (or its designated agent) that can or does execute a Transmission Service agreement or can or does receive Transmission Service. 2. Any of the following entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.
Transmission Operator	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.
Transmission Operator Area	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity that owns and maintains transmission Facilities.
Transmission Planner	Project 2015-04 Alignment of Terms		11/5/2015	1/21/2016	7/1/2016	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Reliability Margin	Version 0 Reliability Standards		2/8/2005	3/16/2007		The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Transmission Reliability Margin Implementation Document	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	11/24/2009		A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service	Version 0 Reliability Standards		2/8/2005	3/16/2007		Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider	Project 2015-04 Alignment of Terms	TSP	11/5/2015	1/21/2016	7/1/2016	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.
Undervoltage Load Shedding Program	Project 2008-02 Undervoltage Load Shedding & Underfrequency Load Shedding	UVLS Program	11/13/2014	11/19/2015	4/1/2017	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate undervoltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled undervoltage-based load shedding is not included.
Vegetation	Project 2007-07 Transmission Vegetation Management		2/7/2006	3/16/2007		All plant material, growing or not, living or dead.
Vegetation Inspection	Project 2010-07		5/9/2012	3/21/2013	7/1/2014	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area	Version 0 Reliability Standards		2/8/2005	3/16/2007		The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.
Year One	Project 2010-10 FAC Order 729		1/24/2011	11/17/2011		The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

PENDING ENFORCEMENT						
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Definition**
Cyber Security Incident	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting		2/7/2019	6/20/2019	1/1/2021	A malicious act or suspicious event that: - For a high or medium impact BES Cyber System, compromises or attempts to compromise (1) an Electronic Security Perimeter, (2) a Physical Security Perimeter, or (3) an Electronic Access Control or Monitoring System; or - Disrupts or attempts to disrupt the operation of a BES Cyber System.
Operational Planning Analysis	Project 2007-06.2 Phase 2 of System Protection Coordination	OPA	8/11/2016	6/7/2018	4/1/2021	An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to: load forecasts; generation output levels; Interchange; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)
Protection System Coordination Study	Project 2007-06 System Protection Coordination		11/5/2015	6/7/2018	4/1/2021	An analysis to determine whether Protection Systems operate in the intended sequence during Faults.
Real-time Assessment	Project 2007-06.2 Phase 2 of System Protection Coordination	RTA	8/11/2016	6/8/2018	4/1/2021	An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load; generation output levels; known Protection System and Remedial Action Scheme status or degradation, functions, and limitations; Transmission outages; generator outages; Interchange; Facility Ratings; and identified phase angle and equipment limitations. (Realtime Assessment may be provided through internal systems or through third-party services.)
Reportable Cyber Security Incident	Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting		2/7/2019	6/20/2019	1/1/2021	A Cyber Security Incident that compromised or disrupted: - A BES Cyber System that performs one or more reliability tasks of a functional entity; - An Electronic Security Perimeter of a high or medium impact BES Cyber System; or - An Electronic Access Control or Monitoring System of a high or medium impact BES Cyber System.

Retired Terms							
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
Adjacent Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact	Project 2006-06		8/4/2011	NERC withdrew the related petition 3/18/2015.			The impact of an event that results in Bulk Electric System instability or Cascading.
Area Control Error	Version 0 Reliability Standards	ACE	2/8/2005	3/16/2007		3/31/2014	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error.
Arranged Interchange	Coordinate Interchange		5/2/2006	3/16/2007		9/30/2014	The state where the Interchange Authority has received the Interchange information (initial or revised).
ATC Path	Project 2006-07		8/22/2008	Not approved; Modification directed 11/24/2009			Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path. (See 18 CFR 37.6(b)(1))
Automatic Generation Control	Version 0 Reliability Standards	AGC	2/8/2005	3/16/2007		12/31/2018	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Transfer Capability	Version 0 Reliability Standards	ATC	2/8/2005	3/16/2007			A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.
Balancing Authority	Version 0 Reliability Standards	BA	2/8/2005	3/16/2007		12/31/2018	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
BES Cyber Asset	Project 2008-06		11/26/2012	11/22/2013		6/30/2016	A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)
Blackstart Capability Plan	Version 0 Reliability Standards		2/8/2005	3/16/2007		7/1/2013 Will be retired when EOP-005-2 becomes enforceable	A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Blackstart Resource	Project 2006-03		8/5/2009	3/17/2011		6/30/2016	A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.

Retired Terms

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Bulk Electric System	Version 0 Reliability Standards	BES	2/8/2005	3/16/2007		6/30/2014	As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.
Bulk Electric System **(Continued)**	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	**I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1. **Exclusions:** • **E1** - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and: a) Only serves Load. Or, b) Only includes generation resources, not identified in Inclusion I3, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or, c) Where the radial system serves Load and includes generation resources, not identified in Inclusion I3, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating). Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.
Bulk Electric System **(Continued)**	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	• **E2** - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority. • **E3** - Local networks (LN): A group of contiguous transmission Elements operated at or above 100 kV but less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customer Load and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:
Bulk Electric System **(Continued)**	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusion I3 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating); b) Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and c) Not part of a Flowgate or transfer path: The LN does not contain a monitored Facility of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL). • E4 – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Retired Terms							
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Bulk Electric System (FERC issued an order on April 18, 2013 approving the revised definition with an effective date of July 1, 2013. On June 14, 2013, FERC granted NERC's request to extend the effective date of the revised definition of the Bulk Electric System to July 1, 2014.)	Project 2010-17	BES	1/18/2012	6/14/2013		Replaced by BES definition FERC approved 3/20/2014	Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. Inclusions: • I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded under Exclusion E1 or E3. • I2 - Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above. • I3 - Blackstart Resources identified in the Transmission Operator's restoration plan. • I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above.
Bulk-Power System	Project 2012-08.1 Phase 1		5/9/2013	7/9/2013		6/30/2016	A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.
Business Practices	Project 2006-07		8/22/2008	Not approved; Modification directed 11/24/2009			Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Cascading	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Cascading Outages	Determine Facility Ratings, Operating Limits, and Trasfer Capabilites		11/1/2006 Withdrawn 2/12/2008			FERC Remanded 12/27/2007	~~The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre-determined area.~~
Confirmed Interchange	Coordinate Interchange		5/2/2006	3/16/2007			The state where the Interchange Authority has verified the Arranged Interchange.
Contingency Reserve	Version 0 Reliability Standards		2/8/2005	3/16/2007		12/31/2017	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.
Critical Assets	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Cyber Assets essential to the reliable operation of Critical Assets.
Cyber Assets	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Programmable electronic devices and communication networks including hardware, software, and data.

Retired Terms							
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Cyber Security Incident	Cyber Security (Permanent)		5/2/2006	1/18/2008		6/30/2016	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Demand-Side Management	Version 0 Reliability Standards	DSM	2/8/2005	3/16/2007		6/30/2016	The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.
Distribution Provider	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Dynamic Interchange Schedule or Dynamic Schedule	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Electronic Security Perimeter	Cyber Security (Permanent)	ESP	5/2/2006	1/18/2008		6/30/2016	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Element	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Energy Emergency	Version 0 Reliability Standards		2/8/2005	3/16/2007		3/31/2017	A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
Flowgate	Version 0 Reliability Standards		2/8/2005	3/16/2007			A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.
Frequency Bias Setting	Version 0 Reliability Standards		2/8/2005	3/16/2007		3/31/2015	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection.
Generator Operator		GOP	2/8/2005	3/16/2007		6/30/2016	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner		GO	2/8/2005	3/16/2007		6/30/2016	Entity that owns and maintains generating units.
Interchange Authority		IA	5/2/2006	3/16/2007		6/30/2016	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Interconnected Operations Service	Version 0 Reliability Standards		2/8/2005	3/16/2007			A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.
Interconnection	Project 2010-14.1 Phase 1		8/15/2013	4/16/2015			When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.
Interconnection Reliability Operating Limit	Version 0 Reliability Standards	IROL	2/8/2005	3/16/2007		12/27/2007	The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.

Retired Terms							
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Intermediate Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007			A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Load-Serving Entity	Version 0 Reliability Standards		2/8/2005	3/16/2007			Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
Low Impact BES Cyber System Electronic Access Point	Project 2014-02	LEAP	2/12/2015	1/21/2016	7/1/2016	12/31/2019	A Cyber Asset interface that controls Low Impact External Routable Connectivity. The Cyber Asset containing the LEAP may reside at a location external to the asset or assets containing low impact BES Cyber Systems.
Low Impact External Routable Connectivity	Project 2014-02	LERC	2/12/2015	1/21/2016	7/1/2016	12/31/2019	Direct user-initiated interactive access or a direct device-to-device connection to a low impact BES Cyber System(s) from a Cyber Asset outside the asset containing those low impact BES Cyber System(s) via a bi-directional routable protocol connection. Point-to-point communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions between Transmission station or substation assets containing low impact BES Cyber Systems are excluded from this definition (examples of this communication include, but are not limited to, IEC 61850 GOOSE or vendor proprietary protocols).
Misoperation	Phase III - IV Planning Standards - Archive		2/7/2006	3/16/2007		6/30/2016	• Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.
Operational Planning Analysis	Operate Within Interconnection Reliability Operating Limits		10/17/2008	3/17/2011		9/30/2014	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Operational Planning Analysis	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	12/31/2016	An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, Interchange, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Physical Security Perimeter	Cyber Security (Permanent)	PSP	5/2/2006	1/18/2008		6/30/2016	The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Planning Authority	Version 0 Reliability Standards	PA	2/8/2005	3/16/2007			The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Point of Receipt	Version 0 Reliability Standards	POR	2/8/2005	3/16/2007		6/30/2016	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Postback	Project 2006-07 ATC/TTC/AFC and CBM/TRM Revisions		8/22/2008	Not approved; Modification directed 11/24/09			Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Retired Terms							
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Protected Cyber Assets	Project 2008-06 Cyber Security Order 706	PCA	11/26/2012	11/22/2013		6/30/2016	One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protection System	Phase III-IV Planning Standards - Archive		2/7/2006	3/17/2007		4/1/2013	Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Protection System Maintenance Program (PRC-005-2)	Project 2007-17 Protection System Maintenance and Testing	PSMP	11/7/2012	12/19/2013		4/1/2015	An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Protection System Maintenance Program (PRC-005-3)	Project 2007-17.2 Protection System Maintenance and Testing - Phase 2	PSMP	11/7/2013	1/22/2015	4/1/2016		An ongoing program by which Protection System and automatic reclosing components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.

Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Retired Terms							
Protection System Maintenance Program (PRC-005-4)	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PSMP	11/13/2014	9/17/2015	1/1/2016		An ongoing program by which Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components are kept in working order and proper operation of malfunctioning Components is restored. A maintenance program for a specific Component includes one or more of the following activities: • Verify — Determine that the Component is functioning correctly. • Monitor — Observe the routine in-service operation of the Component. • Test — Apply signals to a Component to observe functional performance or output behavior, or to diagnose problems. • Inspect — Examine for signs of Component failure, reduced performance or degradation. • Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie	Version 0 Reliability Standards		2/8/2005	3/16/2007			A telemetered reading or value that is updated in real time and used as a “virtual” tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Pseudo-Tie	Project 2008-12		2/6/2014	6/30/2014	10/1/2014	12/31/2018	A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities’ control ACE equations (or alternate control processes).
Reactive Power	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power	Version 0 Reliability Standards		2/8/2005	3/16/2007			The portion of electricity that supplies energy to the load.
Reallocation	Version 0 Reliability Standards		2/8/2005	3/16/2007			The total or partial curtailment of Transactions during TLR Level 3a or 5a to allow Transactions using higher priority to be implemented.
Real-time Assessment	Operate Within Interconnection Reliability Operating Limits		10/17/2008	3/17/2011		12/31/2016	An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data
Reliability Coordinator	Version 0 Reliability Standards	RC	2/8/2005	3/16/2007		6/30/2007	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.
Reliability Directive	Project 2006-06 Reliability Coordination		8/16/2012	11/19/2015		11/19/2015	A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.

Retired Terms							
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Reliability Standard	Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions		5/9/2013	7/9/2013		6/30/2016	A requirement, approved by the United States Federal Energy Regulatory Commission under this Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System]. The term includes requirements for the operation of existing bulk-power system [Bulk-Power System] facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation [Reliable Operation] of the bulk-power system [Bulk-Power System], but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
Reliable Operation	Project 2012-08.1 Phase 1 of Glossary Updates: Statutory Definitions		5/9/2013	7/9/2013		6/30/2016	Operating the elements of the bulk-power system [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.
Remedial Action Scheme	Version 0 Reliability Standards	RAS	2/8/2005	3/16/2007		3/31/2017	See "Special Protection System"
Removable Media	Project 2014-02		2/12/2015	1/21/2016	7/1/2016	12/31/2019	Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.
Reporting Ace			8/15/2013	4/16/2015 (Will not go into effect)			The scan rate values of a Balancing Authority's Area Control Error (ACE) measured in MW, which includes the difference between the Balancing Authority's Net Actual Interchange and its Net Scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction (ATEC). Reporting ACE is calculated as follows: Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$ Where: **NI_A (Actual Net Interchange)** is the algebraic sum of actual megawatt transfers across all Tie Lines and includes Pseudo-Ties. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie lines in their actual interchange, provided they are implemented in the same manner for Net Interchange Schedule. **NI_S (Scheduled Net Interchange)** is the algebraic sum of all scheduled megawatt transfers, including Dynamic Schedules, with adjacent Balancing Authorities, and taking into account the effects of schedule ramps. Balancing Authorities directly connected via asynchronous ties to another Interconnection may include or exclude megawatt transfers on those Tie Lines in their scheduled Interchange, provided they are implemented in the same manner for Net Interchange Actual.

Retired Terms							
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
Reporting Ace **(Continued)**			8/15/2013	4/16/2015 (Will not go into effect)			**B (Frequency Bias Setting**) is the Frequency Bias Setting (in negative MW/0.1 Hz) for the Balancing Authority. **10** is the constant factor that converts the frequency bias setting units to MW/Hz. **F_A (Actual Frequency)** is the measured frequency in Hz. **F_S (Scheduled Frequency)** is 60.0 Hz, except during a time correction. **I_{ME} (Interchange Meter Error)** is the meter error correction factor and represents the difference between the integrated hourly average of the net interchange actual (NIA) and the cumulative hourly net Interchange energy measurement (in megawatt-hours). **I_{ATEC} (Automatic Time Error Correction)** is the addition of a component to the ACE equation for the Western Interconnection that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error. Automatic Time Error Correction is only applicable in the Western Interconnection. $_{ATEC}$ shall be zero when operating in any other AGC mode. • Y = B / BS. • H = Number of hours used t[illegible] when operating in Automatic Time Error Correction control mode gy. The value of H is set to 3. • BS = Frequency Bias for the
Reporting Ace **(Continued)**							energy. The value of H is set to 3. B_S = Frequency Bias for the Interconnection (MW / 0.1 Hz). • Primary Inadvertent Interchange (PII_{hourly}) is (1-Y) * (II_{actual} - B * ΔTE/6) • II_{actual} is the hourly Inadvertent Interchange for the last hour. • ΔTE is the hourly change in system Time Error as distributed by the Interconnection Time Monitor. Where:ΔTE = TE_{end} hour – $TE_{begin\ hour}$ – TD_{adj} – (t)*(TE_{offset}) • TD_{adj} is the Reliability Coordinator adjustment for differences with Interconnection Time Monitor control center clocks. • t is the number of minutes of Manual Time Error Correction that occurred during the hour. • TE_{offset} is 0.000 or +0.020 or -0.020. • PII_{accum} is the Balancing Authority's accumulated PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required. Where: All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAs on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation
Reporting Ace **(Continued)**			8/15/2013	4/16/2015 (Will not go into effect)			All NERC Interconnections with multiple Balancing Authorities operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all Balancing Authorities on an interconnection and is(are) consistent with the following four principles will provide a valid alternative Reporting ACE equation consistent with the measures included in this standard. 1. All portions of the Interconnection are included in one area or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses. 2. The algebraic sum of all area Net Interchange Schedules and all Net Interchange actual values is equal to zero at all times. 3. The use of a common Scheduled Frequency FS for all areas at all times. 4. The absence of metering or computational errors. (The inclusion and use of the IME term to account for known metering or computational errors.)
Request for Interchange	[Coordinate Interchange]()	RFI	5/2/2006	3/16/2007			A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.

Retired Terms							
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
Reserve Sharing Group	Version 0 Reliability Standards	RSG	2/8/2005	3/16/2007		6/30/2016	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.
Reserve Sharing Group Reporting ACE	Project 2010-14.1 Phase 1		8/15/2013	4/16/2015		12/31/2017	At any given time of measurement for the applicable Reserve Sharing Group, the algebraic sum of the Reporting ACEs (or equivalent as calculated at such time of measurement) of the Balancing Authorities participating in the Reserve Sharing Group at the time of measurement.
Resource Planner	Version 0 Reliability Standards	RP	2/8/2005	3/16/2007			The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.
Right-of-Way	Project 2007-07	ROW	2/7/2006	3/16/2007			A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Right-of-Way	Project 2007-07	ROW	11/3/2011	3/21/2013		6/30/2014	The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Sink Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority	Version 0 Reliability Standards		2/8/2005	3/16/2007		9/30/2014	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System (Remedial Action Scheme)	Version 0 Reliability Standards	SPS	2/8/2005	3/16/2007 (Becomes inactive 3/31/2017)		3/31/2017	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

Retired Terms							
Continent-wide Term	**Link to Project Page**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
System Operating Limit	Version 0 Reliability Standards	SOL	2/8/2005	3/16/2007		6/30/2014	The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)
System Operator	Version 0 Reliability Standards		2/8/2005	3/16/2007		6/30/2016	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.
Transient Cyber Asset	Project 2014-02		2/12/2015	1/21/2016	7/1/2016		A Cyber Asset that (i) is capable of transmitting or transferring executable code, (ii) is not included in a BES Cyber System, (iii) is not a Protected Cyber Asset (PCA), and (iv) is directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless, including near field or Bluetooth communication) for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a PCA. Examples include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.

NPCC REGIONAL DEFINITIONS							
NPCC Regional Term	Link to Implementation Plan	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Current Zero Time	PRC-002-NPCC-1 Implementation Plan		11/4/2010	10/20/2011	10/20/2013		The time of the final current zero on the last phase to interrupt.
Generating Plant	PRC-002-NPCC-1 Implementation Plan		11/4/2010	10/20/2011	10/20/2013		One or more generators at a single physical location whereby any single contingency can affect all the generators at that location.

RELIABILITYFIRST REGIONAL DEFINITIONS							
RELIABILITYFIRST Regional Term	Link to FERC Order	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Resource Adequacy	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)
Net Internal Demand	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Management and Interruptible Demand
Peak Period	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity’s annual peak demand is expected to occur
Wind Generating Station	BAL-502-RFC-02 Implementation Plan		11/3/2011 (Board withdrew approval 11/7/2012)	3/17/2011			A collection of wind turbines electrically connected together and injecting energy into the grid at one point, sometimes known as a “Wind Farm.”
Year One	BAL-502-RFC-02 Implementation Plan		8/5/2009	3/17/2011			The planning year that begins with the upcoming annual Peak Period

TEXAS RE REGIONAL DEFINITIONS

Frequency Measurable Event	BAL-001-TRE-1 Implementation Plan	FME	8/15/2013	1/16/2014	4/1/2014		An event that results in a Frequency Deviation, identified at the BA's sole discretion, and meeting one of the following conditions: i) a Frequency Deviation that has a pre-perturbation [the 16-second period of time before t(0)] average frequency to post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency absolute deviation greater than 100 mHz (the 100 mHz value may be adjusted by the BA to capture 30 to 40 events per year). Or ii) a cumulative change in generating unit/generating facility, DC tie and/or firm load pre-perturbation megawatt value to post-perturbation megawatt value absolute deviation greater than 550 MW (the 550 MW value may be adjusted by the BA to capture 30 to 40 events per year).
Governor			8/15/2013	1/16/2014	4/1/2014		The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.
Primary Frequency Response	BAL-001-TRE-1 Implementation Plan	PFR	8/15/2013	1/16/2014	4/1/2014		The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency.

WECC REGIONAL DEFINITIONS

WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Area Control Error *	WECC Regional Standards Under Development	ACE	3/12/2007	6/8/2007		3/31/2014	Means the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.
Automatic Generation Control *	WECC Regional Standards Under Development	AGC	3/12/2007	6/8/2007			Means equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.
Automatic Time Error Correction	WECC Regional Standards Under Development		3/26/2008	5/21/2009		3/31/2014	A frequency control automatic action that a Balancing Authority uses to offset its frequency contribution to support the Interconnection's scheduled frequency.
Automatic Time Error Correction	WECC Regional Standards Under Development		12/19/2012	10/16/2013	4/1/2014		The addition of a component to the ACE equation that modifies the control point for the purpose of continuously paying back Primary Inadvertent Interchange to correct accumulated time error.
Average Generation *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means the total MWh generated within the Balancing Authority Operator's Balancing Authority Area during the prior year divided by 8760 hours (8784 hours if the prior year had 366 days).

Business Day *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means any day other than Saturday, Sunday, or a legal public holiday as designated in section 6103 of title 5, U.S. Code.
Commercial Operation	WECC Regional Standards Under Development		10/29/2008	4/21/2011			Achievement of this designation indicates that the Generator Operator or Transmission Operator of the synchronous generator or synchronous condenser has received all approvals necessary for operation after completion of initial start-up testing.
Contributing Schedule	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	A Schedule not on the Qualified Transfer Path between a Source Balancing Authority and a Sink Balancing Authority that contributes unscheduled flow across the Qualified Transfer Path.
Dependability-Based Misoperation	WECC Regional Standards Under Development		10/29/2008	4/21/2011			Is the absence of a Protection System or RAS operation when intended. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Disturbance *	WECC Regional Standards Under Development		3/12/2007	6/8/2007		Retired	Means (i) any perturbation to the electric system, or (ii) the unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.
Extraordinary Contingency†	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Shall have the meaning set out in Excuse of Performance, section B.4.c. language in section B.4.c: *means any act of God, actions by a non-affiliated third party, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, accident to or breakage, failure or malfunction of machinery or equipment, or any other cause beyond the Reliability Entity's reasonable control; provided that prudent industry standards (e.g. maintenance, design, operation) have been employed; and provided further that no act or cause shall be considered an Extraordinary Contingency if such act or cause results in any contingency contemplated in any WECC Reliability Standard (e.g., the "Most Severe Single Contingency" as defined in the WECC Reliability Criteria or any lesser contingency).*

WECC REGIONAL DEFINITIONS

WECC Regional Term	WECC Standards Under Development	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Frequency Bias *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means a value, usually given in megawatts per 0.1 Hertz, associated with a Control Area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Functionally Equivalent Protection System	WECC Regional Standards Under Development	FEPS	10/29/2008	4/21/2011			A Protection System that provides performance as follows: • Each Protection System can detect the same faults within the zone of protection and provide the clearing times and coordination needed to comply with all Reliability Standards. • Each Protection System may have different components and operating characteristics.
Functionally Equivalent RAS	WECC Regional Standards Under Development	FERAS	10/29/2008	4/21/2011			A Remedial Action Scheme ("RAS") that provides the same performance as follows: • Each RAS can detect the same conditions and provide mitigation to comply with all Reliability Standards. • Each RAS may have different components and operating characteristics.
Generating Unit Capability *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means the MVA nameplate rating of a generator.
Non-spinning Reserve†	WECC Regional Standards Under Development		3/12/2007	6/8/2007		Retired	Means that Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.
Normal Path Rating *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Is the maximum path rating in MW that has been demonstrated to WECC through study results or actual operation, whichever is greater. For a path with transfer capability limits that vary seasonally, it is the maximum of all the seasonal values.
Operating Reserve *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means that capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.
Operating Transfer Capability Limit *	WECC Regional Standards Under Development	OTC	3/12/2007	6/8/2007			Means the maximum value of the most critical system operating parameter(s) which meets: (a) precontingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) transient criteria as determined by equipment loading capability and acceptable voltage conditions, (c) transient performance criteria, and (d) post-contingency loading and voltage criteria.
Primary Inadvertent Interchange	WECC Regional Standards Under Development		3/26/2008	5/21/2009			The component of area (n) inadvertent interchange caused by the regulating deficiencies of the area (n).
Qualified Controllable Device	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	A controllable device installed in the Interconnection for controlling energy flow and the WECC Operating Committee has approved using the device for controlling the USF on the Qualified Transfer Paths.
Qualified Path	WECC Regional Standards Under Development		2/7/2019	5/10/2019	10/1/2019		A transmission element, or group of transmission elements that has qualified for inclusion into the Western Interconnection Unscheduled Flow Mitigation Plan (WIUFMP).
Qualified Transfer Path	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	A transfer path designated by the WECC Operating Committee as being qualified for WECC unscheduled flow mitigation.
Qualified Transfer Path Curtailment Event	WECC Regional Standards Under Development		2/10/2009	3/17/2011		9/30/2019	Each hour that a Transmission Operator calls for Step 4 or higher for one or more consecutive hours (See Attachment 1 IRO-006-WECC-1) during which the curtailment tool is functional.

WECC REGIONAL DEFINITIONS							
WECC Regional Term	**WECC Standards Under Development**	**Acronym**	**BOT Adoption Date**	**FERC Approval Date**	**Effective Date**	**Inactive Date**	**Definition**
Relief Requirement	WECC Regional Standards Under Development		2/10/2009	3/17/2011		6/30/2014	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages listed in the columns of WECC Unscheduled Flow Mitigation Summary of Actions Table in Attachment 1 WECC IRO-006-WECC-1.
Relief Requirement	WECC Regional Standards Under Development		2/7/2013	6/13/2014	7/1/2014	9/30/2019	The expected amount of the unscheduled flow reduction on the Qualified Transfer Path that would result by curtailing each Sink Balancing Authority's Contributing Schedules by the percentages determined in the WECC unscheduled flow mitigation guideline.
Secondary Inadvertent Interchange	WECC Regional Standards Under Development		3/26/2008	5/21/2009			The component of area (n) inadvertent interchange caused by the regulating deficiencies of area (i).
Security-Based Misoperation	WECC Regional Standards Under Development		10/29/2008	4/21/2011			A Misoperation caused by the incorrect operation of a Protection System or RAS. Security is a component of reliability and is the measure of a device's certainty not to operate falsely.
Spinning Reserve†	WECC Regional Standards Under Development		3/12/2007	6/8/2007		Retired	Means unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve (as each are described in Sections B.a.i and ii).
Transfer Distribution Factor	WECC Regional Standards Under Development	TDF	2/10/2009	3/17/2011		9/30/2019	The percentage of USF that flows across a Qualified Transfer Path when an Interchange Transaction (Contributing Schedule) is implemented. [See the WECC Unscheduled Flow Mitigation Summary of Actions Table (Attachment 1 WECC IRO-006-WECC-1).]
WECC Table 2 *	WECC Regional Standards Under Development		3/12/2007	6/8/2007			Means the table maintained by the WECC identifying those transfer paths monitored by the WECC regional Reliability coordinators. As of the date set out therein, the transmission paths identified in Table 2 are as listed in Attachment A to this Standard.

† FERC approved the WECC Tier One Reliability Standards in the Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, 119 FERC ¶ 61,260 (June 8, 2007). In that Order, FERC directed WECC to address the inconsistencies between the regional definitions and the NERC Glossary in developing permanent replacement standards. The replacement standards designed to address the shortcomings were filed with FERC in 2009.

CHANGE HISTORY	
Date	**Action**
10/8/2020	Retired; moved to the Retired Terms tab. 1. Automatic Generation Control 2. Balancing Authority 3. Pseudo-Tie
5/29/2020	Updated effective date for Operational Planning Analysis (OPA), Protections System Coordination Study and Real-time Assessment (RTA) to 4/21/2021 per FERC/s April 17th Order extending effective dates due to COVID-19.
2/24/2020	Added inactive Date to Qualified Transfer Path Curtailment Event, Contributing Schedule, Qualified Controllable Device, Relief Requirement and Transfer Distribution Factor.
1/2/2020	Effective; moved to the Subject to Enforcement tab: 1. Definition of Transient Cyber Asset (TCA) 2. Definition of Removable Media
1/2/2020	Retired; moved to the Retired Terms tab. 1. Low Impact BES Cyber System Electronic Access Point (LEAP) 2. Low Impact External Routable Connectivity (LERC) 3. Transient Cyber Asset (TCA) 4. Removable Media
8/12/2019	Added revised definitions of Cyber Security Incident and Reportable Cyber Security Incident to the Pending Enforcement tab.
5/10/2019	Added Inactive Date to Qualified Transfer Path. Added Qualified Path definition and Effective Date
3/8/2019	Moved "Automatic Generation Control," "Balancing Authority" and "Pseudo-tie" to Subject to Enforcement tab.
7/3/2018	Updated effective date for Operational Planning Analysis (OPA), Protections System Coordination Study and Real-time Assessment (RTA).
6/12/2018	Added revised definitions of Transient Cyber Asset and Removable Media to the Pending Enforcement tab.
1/31/2018	Fixed truncated definition for Texas RE term Primary Frequency Response
1/2/2018	**Moved to Subject to Enforcement**: Balancing Contingency Event; Contingency Event Recovery Period; Contingency Reserve; Contingency Reserve Restoration Period; Most Severe Single Contingency; Pre-Reporting Contingency Event ACE Value; Reportable Balancing Contingency Event; Reserve Sharing Group Reporting ACE **Moved to Retired tab**: Contingency Reserve; Reserve Sharing Group Reporting ACE
10/6/2017	Added the Effective date of Automatic Generation Control, Pseudo-Tie and Balancing Authority
8/1/2017	Moved to Subject to Enforcement: Reporting Ace, Actual Frequency, Actual Net Interchange, Schedule Net Interchange, Interchange Meter Error, Automatic Time Error Correction
7/24/2017	Updated project link for definitions related to Project 2014-02, board adopted 2/12/15.
7/14/2017	Updated project link to Remedial Action Scheme with an effective date of 4/1/17; Removeable Media link to project 2014-02.
7/3/2017	Moved 'Geomagnetic Disturbance Vulnerability Assessment or GMD Vunerability Assessment' to Subject to Enforcement
6/15/2017	Readded 'Governor' and 'Primary Frequency Response' to TexasRE
4/4/2017	Moved to Subject to Enforcement: Energy Emergency, Remedial Action Scheme, Special Protection System and Under3 Voltage Load Shedding Program. Moved terms inactive 3/31/17 to Retired tab.
3/16/2017	Removed Pending Inactive tab; not necessary
3/10/2017	Added **Pending Inactive** tab
2/7/2017	**Added Effective Dates for:** Balancing Contingency Event, Most Severe Single Contingency (MSSC), Reportable Balancing Contingency Event, Contingency Event Recovery Period, Contingency Reserve Restoration Period, Pre-Reporting Contingency Event ACE Value, Reserve Sharing Group Reporting ACE, Contingency Reserve
1/25/2017	Removed WECC terms 'Non-Spinning Reserve' and 'Spinning Reserve' per FERC Order No. 789. Docket No. RM13-13-000.
1/6/2017	Moved the following terms from Pending Enforcement to Subject to Enforcement: Operational Planning Analysis, Real-time Assessment (Revised Definition)
1/5/2017	**Formatting of Glossary of Terms updated.**
12/12/16	**Updated:** 'Adverse Reliability Impact' from Pending to Retired. NERC withdrew the related petition 3/18/2015
11/28/16	**Updated** ReliabilityFirst - Wind Generating Station term to inactive
9/28/16	**Updated** CIP v 5 standards effective date from 4/1/2016 to 7/1/2016 per FERC Order 822.
8/17/16	**Board Adopted:** Operational Planning Analysis and Real-time Assessment
7/13/16	Updated color coding of terms retired 6/30/2016 based on the terms becoming effective 7/1/2016.
6/24/16	**FERC approved:** Actual Frequency, Actual Net Interchange, Scheduled Net Interchange (NIS), Interchange Meter Error (IME), and Automatic Time Error Correction (ATEC) Reporting ACE: status updated
6/21/16	**Correction:** Reserve Sharing Group Reporting ACE, and Contingency Reserve changed to 11/5/2015 Board adoption date status
4/1/16	**Effective:** BES Cyber Asset, BES Cyber System, BES Cyber System Information, CIP Exceptional Circumstance, CIP Senior Manager, Cyber Assets, Cyber Security Incident, Dial-up Connectivity, Electronic Access Control or Monitoring Systems, Electronic Access Point, Electronic Security Perimeter, External Routable Connectivity, Interactive Remote Access, Intermediate System, Physical Access Control Systems, Physical Security Perimeter
3/31/16	**Inactive**: Critical Assets, Critical Cyber Assets, Cyber Assets, Cyber Security Incident, Electronic Security Perimeter, Physical Security Perimeter

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BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

Appendix C-1

BC Hydro Feedback Survey Forms

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard)	RSAW Link (Hyperlinks to the available RSAWs)	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document (Hyperlinks to the mapping documents if available)	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date (Hyperlinks to the referenced FERC Orders)	Effective Date of FERC Rule Approving the Standard (Hyperlinks to the FERC Approval Ruling)	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date (Hyperlinks to the respective implementation plan and effective dates if applicable)	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($): One Time ($)	Ongoing ($)	Cost Comments	BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
EOP-003-2 R1	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	EOP-003-2 Mapping Document	BA, TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R2	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Plans needed for automatic load shedding for underfrequency or undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2 Mapping Document	TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R3	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Added text excluding automatic under-frequency load shedding plans	EOP-003-2 Mapping Document	BA, TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R4	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R5	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Added text excluding automatic under-frequency load shedding plans	EOP-003-2 Mapping Document	BA, TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R6	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	EOP-003-2 Mapping Document	BA, TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R7	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
EOP-003-2 R8	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	EOP-003-2 Mapping Document	BA, TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.	0	0		Superseded by EOP-011-1 (currently effective in BC) in conjunction with PRC-010-2, which is being recommended for adoption under PC assessment report. Therefore not recommended for adoption in BC in which case no incremental cost.
FAC-013-2 R1 RETIRE	N/A Retired	**Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.	FAC-013-2 in Abeyance	FAC-013-1 Adopted 2008 Assessment Report 1 G-67-09	N/A - Retired Standard	N/A - Retired Standard	PA, PC		Recommend for Retirement RM19-16-000 & RM19-17-000	Recommend for Retirement Order No. 873 Issued Sept 17, 2020	As we expect recommend this standard not be adopted in BC (or if it is that it be retired immediately), we expect no incremental costs and negligible impact. No incremental costs expected; negligible impact.	0	0		Recommend that this standard is not adopted in BC. Recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.
FAC-013-2 R2 RETIRE	N/A Retired	**Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.	FAC-013-2 in Abeyance	FAC-013-1 Adopted 2008 Assessment Report 1 G-67-09	N/A - Retired Standard	N/A - Retired Standard	PA, PC		Recommend for Retirement RM19-16-000 & RM19-17-000	Recommend for Retirement Order No. 873 Issued Sept 17, 2020	As we expect recommend this standard not be adopted in BC (or if it is that it be retired immediately), we expect no incremental costs and negligible impact. No incremental costs expected; negligible impact.	0	0		Recommend that this standard is not adopted in BC. Recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.
FAC-013-2 R3 RETIRE	N/A Retired	**Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.	FAC-013-2 in Abeyance	FAC-013-1 Adopted 2008 Assessment Report 1 G-67-09	N/A - Retired Standard	N/A - Retired Standard	PA, PC		Recommend for Retirement RM19-16-000 & RM19-17-000	Recommend for Retirement Order No. 873 Issued Sept 17, 2020	As we expect recommend this standard not be adopted in BC (or if it is that it be retired immediately), we expect no incremental costs and negligible impact. No incremental costs expected; negligible impact.	0	0		Recommend that this standard is not adopted in BC. Recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.
FAC-013-2 R4 RETIRE	N/A Retired	**Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.	FAC-013-2 in Abeyance	FAC-013-1 Adopted 2008 Assessment Report 1 G-67-09	N/A - Retired Standard	N/A - Retired Standard	PA, PC		Recommend for Retirement RM19-16-000 & RM19-17-000	Recommend for Retirement Order No. 873 Issued Sept 17, 2020	As we expect recommend this standard not be adopted in BC (or if it is that it be retired immediately), we expect no incremental costs and negligible impact. No incremental costs expected; negligible impact.	0	0		Recommend that this standard is not adopted in BC. Recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.

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BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard)	RSAW Link (Hyperlinks to the available RSAWs)	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document (Hyperlinks to the mapping documents if available)	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date (Hyperlinks to the referenced FERC Orders)	Effective Date of FERC Rule Approving the Standard (Hyperlinks to the FERC Approval Ruling)	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date (Hyperlinks to the respective implementation plan and effective dates if applicable)	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($) One Time ($)	Ongoing ($)	Cost Comments	BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
FAC-013-2 R5 RETIRE	N/A Retired	**Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.	FAC-013-2 in Abeyance	FAC-013-1 Adopted 2008 Assessment Report 1 G-67-09	N/A - Retired Standard	N/A - Retired Standard	PA, PC		Recommend for Retirement RM19-16-000 & RM19-17-000	Recommend for Retirement Order No. 873 Issued Sept 17, 2020	As we expect recommend this standard not be adopted in BC (or if it is that it be retired immediately), we expect no incremental costs and negligible impact. No incremental costs expected; negligible impact.	0	0		Recommend that this standard is not adopted in BC. Recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.
FAC-013-2 R6 RETIRE	N/A Retired	**Title: Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon** To ensure that Planning Coordinators have a methodology for, and perform an annual assessment to identify potential future Transmission System weaknesses and limiting Facilities that could impact the Bulk Electric System's (BES) ability to reliably transfer energy in the Near-Term Transmission Planning Horizon.	FAC-013-2 in Abeyance	FAC-013-1 Adopted 2008 Assessment Report 1 G-67-09	N/A - Retired Standard	N/A - Retired Standard	PA, PC		Recommend for Retirement RM19-16-000 & RM19-17-000	Recommend for Retirement Order No. 873 Issued Sept 17, 2020	As we expect recommend this standard not be adopted in BC (or if it is that it be retired immediately), we expect no incremental costs and negligible impact. No incremental costs expected; negligible impact.	0	0		Recommend that this standard is not adopted in BC. Recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.
MOD-032-1 R1	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. Added entities responsible for providing the data in R1.3	MOD-032-1 Mapping Docume	PA, PC, TP	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	BC Hydro will need to develop process and procedures for the new data and reporting requirements. Estimated ~25,000 one time incremental cost.	25,000	0		R1: first day of the first calendar quarter that is 12 months after BCUC adoption. R2 - R4: first day of the first calendar quarter that is 24 months after BCUC adoption.
MOD-032-1 R2	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Docume	BA, GO, LSE, RP,	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	BC Hydro will need to verify data sources and develop and maintain data management systems. Estimate ~$500,000 one time and ~$40,000 on going incremental cost.	500,000	40,000		R1: first day of the first calendar quarter that is 12 months after BCUC adoption. R2 - R4: first day of the first calendar quarter that is 24 months after BCUC adoption.
MOD-032-1 R3	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Docume	BA, GO, LSE, RP,	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	Minimal incremental costs expected; negligible impact.	0	0		R1: first day of the first calendar quarter that is 12 months after BCUC adoption. R2 - R4: first day of the first calendar quarter that is 24 months after BCUC adoption.
MOD-032-1 R4	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Docume	PA, PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	Minimal incremental costs expected; negligible impact.	0	0		R1: first day of the first calendar quarter that is 12 months after BCUC adoption. R2 - R4: first day of the first calendar quarter that is 24 months after BCUC adoption.
MOD-033-2 R1	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	BC Hydro will need to develop and implement system model validation process and complete initial validation. Estimated ~$140,000 one time and ~$40,000 on-going incremental cost.	140,000	40,000		Effective first day of the first calendar quarter that is thirty six (36) months after BCUC adoption to align with the total implementation time US entities were afforded when adopting MOD-033-1.
MOD-033-2 R2	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	RC, TOP	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	BC Hydro will need to develop and implement internal procedures to meet the requirement. Estimated ~ $32,000 one time and $10,000 on-going incremental cost.	32,000	10,000		Effective first day of the first calendar quarter that is thirty six (36) months after BCUC adoption to align with the total implementation time US entities were afforded when adopting MOD-033-1.
PRC-006-4 DB1	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	DP, DPUF, PC, TO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	BC Hydro will need to participate in WECC meetings, review reports and run studies for initial compliance. BC Hydro may need to modify its UFLS program under this new version, PRC-006-4.As part of determining if modifications to BC Hydro's UFLS program are required, BC Hydro will need to assess how entities forming part of BC Hydro's UFLS program will need to participate. The mitigation or capital projects may include entities forming part of BC Hydro's UFLS program registering under MRS, BC Hydro or other entities modifying equipment, and/or BC Hydro taking ownership, operations and/or control of some equipment currently owned, operated and/or controlled by other entities. Unable to assess the one-time and ongoing costs required to mitigate issues and/or implement capital projects at this time as these are dependent on the results of the WECC meetings, study results, and discussions with entities forming part of BC Hydro's UFLS program. Estimated ~ $1,530,000 one time and $30,000 on-going incremental cost for WECC meetings, studies, and discussions with entities forming part of BC Hydro's UFLS program. BC Hydro is unable to assess the one time and ongoing costs to mitigate issues and/or implement capital projects at this time as these are dependent on the results of the studies and discussions with the entities forming part of BC Hydro's UFLS program.	1,530,000 PLUS Unable to assess the one time or ongoing costs at this time as this is dependent on the results of studies and discussions.	30,000 PLUS Unable to assess the one time or ongoing costs at this time as this is dependent on the results of studies and discussions.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro's UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro's UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 DB11	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro's UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro's UFLS program will need to participate requires an extended timeframe. PRC-

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FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 DB12	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-
PRC-006-4 DB2	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	Minimal incremental costs expected; negligible impact.	0	0		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 DB3	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 DB4	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	Minimal incremental costs expected; negligible impact.	0	0		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 R14	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 R15	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	BC Hydro may need to develop mitigation or capital projects related to entities forming part of BC Hydro’s UFLS program depending on the results of assessments under other requirements (e.g. D.B.4 or D.B.12). Estimated ~ $5,000 on-going incremental cost PLUS Unable to assess the one time and ongoing costs to mitigate issues and/or implement capital projects at this time.	0	5,000 PLUS Unable to assess the one time and ongoing costs to mitigate issues and/or implement capital projects at this time.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 R6	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	BC Hydro will need to develop processes and procedures. Estimated ~ $20,000 one time and $5,000 on-going incremental cost.	20,000	5,000		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-
PRC-006-4 R7	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority’s order approving the standard. US Enforcement Date 01-Apr-2021	Minimal incremental costs expected; negligible impact.	0	0		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro’s UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro’s UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 R8	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Minimal incremental costs expected; negligible impact.	0	0		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro's UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro's UFLS program will need to participate requires an extended timeframe. PRC-
PRC-006-4 R9	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro's UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro's UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-006-4 R10	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	TO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.	See R1 for cost of adopting a UFLS program.		PRC-006-1, PRC-006-2 and PRC-006-3 versions were never adopted in BC and were held in abeyance. Any needed modifications to BC Hydro's UFLS program under this new version, PRC-006-4, and assessing how entities forming part of BC Hydro's UFLS program will need to participate requires an extended timeframe. PRC-006-4 should be effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by BCUC for implementation in BC.
PRC-010-2 R1	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 Superceding EOP-003-2 R2, R4, R7 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA, PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	BC Hydro currently does not have an applicable UVLS and therefore currently does not have a UVLS Program. BC Hydro will need to evaluate the effectiveness of its UVLS Program if it needs to develop one as a PC and provide the UVLS Program's specifications and implementation schedule. Estimated ~$10,000 on-going incremental cost.	0	10,000		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R2	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	DP, TO	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	0	0		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R3	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA, PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	0	0		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R4	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Added subpoints: 4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and 4.2. The performance (i.e., operation and non-operation) of the UVLS Program equipment.	PRC-010-2 Mapping Document	PA, PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	0	0		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R5	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Removed deficiencies in its UVLS Program	PRC-010-2 Mapping Document	PA, PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R6	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA, PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R7	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	DP, TO	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.
PRC-010-2 R8	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA, PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC-010-2 shall become effective on the later of the first day following the Effective Date of PRC-010-1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.

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BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard)	RSAW Link (Hyperlinks to the available RSAWs)	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document (Hyperlinks to the mapping documents if available)	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date (Hyperlinks to the referenced FERC Orders)	Effective Date of FERC Rule Approving the Standard (Hyperlinks to the FERC Approval Ruling)	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date (Hyperlinks to the respective implementation plan and effective dates if applicable)	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($) One Time ($)	Ongoing ($)	Cost Comments	BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
PRC-012-2 R1 Specifically reference to Attachment 1, Section II Parts 6d and 6e	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	DP, GO, TO	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	BC Hydro will need to develop processes and procedures. Estimated ~ $15,000 one time incremental cost.	15,000	0		No change to the October 1, 2021 future effective date in B.C. and B.C. specific PRC-012-2 Implementation Plan adopted per BCUC Order No. R-33-18 with the following exception. R4: The first day of the first calendar quarter, sixty (60) months after BCUC adoption.
PRC-012-2 R2 Specifically reference to Attachment 2 Section I Parts 7d and 7e	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	RC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		No change to the October 1, 2021 future effective date in B.C. and B.C. specific PRC-012-2 Implementation Plan adopted per BCUC Order No. R-33-18 with the following exception. R4: The first day of the first calendar quarter, sixty (60) months after BCUC adoption.
PRC-012-2 R4	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Abeyance Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA, PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	BC Hydro will need to develop study plan, undertake RAS evaluation study and update processes and complete studies for initial compliance. Estimated ~$507,000 one time and $107,000 on-going incremental cost.	507,000	107,000		No change to the October 1, 2021 future effective date in B.C. and B.C. specific PRC-012-2 Implementation Plan adopted per BCUC Order No. R-33-18 with the following exception. R4: The first day of the first calendar quarter, sixty (60) months after BCUC adoption.
PRC-023-2 R1 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1	PRC-023-2 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	N/A	N/A	N/A	DP, GO, TO	Docket No. RM11-16-000; Order No. 759; March 15, 2012	2012-05-07	PRC-023-2 Implementation Plan R1 - 1st day of the first calendar quarter, after FERC approvals; R2, R3 - 1st day of the first calendar quarter after FERC approvals; R4 - 1st day of the first calendar quarter 6 months after FERC approval; R5 - 1st day of the first calendar quarter 6 months after FERC approvals; R6 - 1st day of the first calendar quarter 18 months after FERC approvals US Enforcement Date 01-Jul-2012	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		Align implementation of PRC-023-2 with implementation of PRC-023-4, namely: No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-2 R2 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1	PRC-023-2 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	N/A	N/A	N/A	DP, GO, TO	Docket No. RM11-16-000; Order No. 759; March 15, 2012	2012-05-07	PRC-023-2 Implementation Plan R1 - 1st day of the first calendar quarter, after FERC approvals; R2, R3 - 1st day of the first calendar quarter after FERC approvals; R4 - 1st day of the first calendar quarter 6 months after FERC approval; R5 - 1st day of the first calendar quarter 6 months after FERC approvals; R6 - 1st day of the first calendar quarter 18 months after FERC approvals US Enforcement Date 01-Jul-2012	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		Align implementation of PRC-023-2 with implementation of PRC-023-4, namely: No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-2 R3 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1	PRC-023-2 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	N/A	N/A	N/A	DP, GO, TO	Docket No. RM11-16-000; Order No. 759; March 15, 2012	2012-05-07	PRC-023-2 Implementation Plan R1 - 1st day of the first calendar quarter, after FERC approvals; R2, R3 - 1st day of the first calendar quarter after FERC approvals; R4 - 1st day of the first calendar quarter 6 months after FERC approval; R5 - 1st day of the first calendar quarter 6 months after FERC approvals; R6 - 1st day of the first calendar quarter 18 months after FERC approvals US Enforcement Date 01-Jul-2012	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		Align implementation of PRC-023-2 with implementation of PRC-023-4, namely: No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-2 R4 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1	PRC-023-2 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	N/A	N/A	N/A	DP, GO, TO	Docket No. RM11-16-000; Order No. 759; March 15, 2012	2012-05-07	PRC-023-2 Implementation Plan R1 - 1st day of the first calendar quarter, after FERC approvals; R2, R3 - 1st day of the first calendar quarter after FERC approvals; R4 - 1st day of the first calendar quarter 6 months after FERC approval; R5 - 1st day of the first calendar quarter 6 months after FERC approvals; R6 - 1st day of the first calendar quarter 18 months after FERC approvals US Enforcement Date 01-Jul-2012	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		Align implementation of PRC-023-2 with implementation of PRC-023-4, namely: No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-2 R5 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1	PRC-023-2 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	N/A	N/A	N/A	DP, GO, TO	Docket No. RM11-16-000; Order No. 759; March 15, 2012	2012-05-07	PRC-023-2 Implementation Plan R1 - 1st day of the first calendar quarter, after FERC approvals; R2, R3 - 1st day of the first calendar quarter after FERC approvals; R4 - 1st day of the first calendar quarter 6 months after FERC approval; R5 - 1st day of the first calendar quarter 6 months after FERC approvals; R6 - 1st day of the first calendar quarter 18 months after FERC approvals US Enforcement Date 01-Jan-2014	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		Align implementation of PRC-023-2 with implementation of PRC-023-4, namely: No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-2 R6 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement 1	PRC-023-2 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	N/A	N/A	N/A	PA, PC	Docket No. RM11-16-000; Order No. 759; March 15, 2012	2012-05-07	PRC-023-2 Implementation Plan R1 - 1st day of the first calendar quarter, after FERC approvals; R2, R3 - 1st day of the first calendar quarter after FERC approvals; R4 - 1st day of the first calendar quarter 6 months after FERC approval; R5 - 1st day of the first calendar quarter 6 months after FERC approvals; R6 - 1st day of the first calendar quarter 18 months after FERC approvals US Enforcement Date 01-Jan-2014	Shared costs with PRC-023-4 R6 - see PRC-023-4 R6.	Shared costs with PRC-023-4 R6 - see PRC-023-4 R6.	Shared costs with PRC-023-4 R6 - see PRC-023-4 R6.		Align implementation of PRC-023-2 with implementation of PRC-023-4, namely: No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard)	RSAW Link (Hyperlinks to the available RSAWs)	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document (Hyperlinks to the mapping documents if available)	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date (Hyperlinks to the referenced FERC Orders)	Effective Date of FERC Rule Approving the Standard (Hyperlinks to the FERC Approval Ruling)	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date (Hyperlinks to the respective implementation plan and effective dates if applicable)	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($) One Time ($)	Ongoing ($)	Cost Comments	BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
PRC-023-4 R1 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. Change to Remedial Action Scheme definition	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-4 R2 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. Change to Remedial Action Scheme definition	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-4 R3 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. Change to Remedial Action Scheme definition	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	BC Hydro will need to develop methodology to evaluate the calculated circuit capability as Facility Rating, and update internal process. In addition, depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6. Estimated ~$15,000 one time and $5,000 on-going incremental cost.	15,000 plus Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	5,000 plus Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-4 R4 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. Change to Remedial Action Scheme definition	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-4 R5 For PC identified circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. Change to Remedial Action Scheme definition	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Depending on R6 assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-023-4 R6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. Change to Remedial Action Scheme definition	N/A	PA, PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	BC Hydro will need to develop process and conduct annual assessment. BC Hydro may also need to assess the impact to other RC related standards including IRO-002, IRO-008, IRO-010, PRC-012, PRC-015, FAC-008 due to the addition of PC function. Depending on assessment results, there may be additional cost incurred from R1-R5 regarding application of settings to additional circuits identified, however it is not possible to estimate cost at this time until the study is performed. Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6. Estimated ~$ 39,000 one time and ~$6,000 on-going incremental cost.	39,000 plus Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.	6,000 plus Unable to assess the one time or ongoing costs at this time as this is dependent on the results of assessments/ studies pursuant to R6.		No change to existing effective dates in B.C. with the following exception. R1-R5 Circuits 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6 and R6: The first day of the first calendar quarter, 12 months after BCUC approval
PRC-026-1 R1	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	PA, PC	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	BC Hydro will need to develop and implement process to perform assessment of power swing conditions. Estimated ~$75,000 one time and ~$20,000 on going incremental cost.	75,000	20,000		R1: first day of the first full calendar year that is 12 months after BCUC adoption. R2 - R4: First day of the first full calendar year that is 36 months after BCUC adoption.
PRC-026-1 R2	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	GO, TO	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	BC Hydro will need to review protection relays which may trip during power swings. Estimated ~$300,000 one time incremental cost.	300,000	0		R1: first day of the first full calendar year that is 12 months after BCUC adoption. R2 - R4: First day of the first full calendar year that is 36 months after BCUC adoption.
PRC-026-1 R3	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	GO, TO	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	BC Hydro will need to develop and implement corrective action plan (CAP). Unable to assess the one time or ongoing costs required to develop and implement corrective action plans (CAPs) at this time as this is dependent on the results of assessments/ studies.	BC Hydro will need to develop and implement corrective action plan (CAP). Unable to assess the one time or ongoing costs required to develop and implement corrective action plans (CAPs) at this time as this is dependent on the results of assessments/ studies.	BC Hydro will need to develop and implement corrective action plan (CAP). Unable to assess the one time or ongoing costs required to develop and implement corrective action plans (CAPs) at this time as this is dependent on the results of assessments/ studies.		R1: first day of the first full calendar year that is 12 months after BCUC adoption. R2 - R4: First day of the first full calendar year that is 36 months after BCUC adoption.
PRC-026-1 R4	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	GO, TO	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	See R3 for cost of implementing CAP.	See R3 for cost of implementing CAP.	See R3 for cost of implementing CAP.		R1: first day of the first full calendar year that is 12 months after BCUC adoption. R2 - R4: First day of the first full calendar year that is 36 months after BCUC adoption.
TPL-001-4 R7	TPL-001-4 RSAW	**Transmission System Planning Performance Requirements** 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.	TPL-001-4 R7 Abeyance	TPL-001-0.1	Currently in Abeyance	Currently in Abeyance	PA, PC	Docket No. RM12-1-000 and RM13-9-000, Order 786; Issue Date: October 17, 2013; Publication Date: October 23, 2013	23-Dec-2013	TPL-001-4 Implementation Plan 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 US Enforcement Date 01-Jan-2015	BC Hydro will need to develop documentation and processes. Estimated ~$5,000 one-time incremental cost.	5,000	0		Effective first day of the first calendar quarter that is three (3) months after the BCUC adoption.

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-001-5.1 R1	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Updated requirement body to reference MOD-032 Part 1.1.2 and subparts have been deleted	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R2	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 2.1.4 moved to Part 2.1.3. A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4. Part 2.1.5 Document internal conforming as reflecting in R2, Part 2.4.5 Part 2.4.3 has been moved back to 2.4.3 as it was in TPL-001-4. Part 2.4.4 TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4.Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4. Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy. Part 2.7 Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard. Part 2.7 Updated to reflect NERC Glossary Term	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	BC Hydro will need to undertake additional assessment related to NCLL. Estimated ~$60,000 on-going incremental cost.	0	60,000		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R3	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 3.2 Document internal conforming clean-up to move the last sentence of Requirement R3, Part 3.5 to Requirement R3, Part 3.2.	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R4	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 4.1.1 Updated to reflect NERC Glossary Term Part 4.2 Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	BC Hydro may need to update protection systems as part of CAPs pursuant to studies performed to meet the requirement. Unable to assess the one time and ongoing costs required develop and implement corrective action plans (CAPs) at this time as this is dependent on the results of studies. Estimate ~$40,000 one time and ~$30,000 on-going incremental cost at minimum.	40,000 plus Unable to assess the one time and ongoing costs required develop and implement corrective action plans (CAPs) at this time as this is dependent on the results of studies.	30,000 plus Unable to assess the one time and ongoing costs required develop and implement corrective action plans (CAPs) at this time as this is dependent on the results of studies.		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R5	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R6	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R7	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.
TPL-001-5.1 R8	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards, and per a B.C. specific TPL-001-5.1 Implementation Plan.

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BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 D.A 11.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See R7 for impact and cost.	See R7 for impact and cost.	See R7 for impact and cost.		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 D.A 11.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See R7 for impact and cost.	See R7 for impact and cost.	See R7 for impact and cost.		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 D.A 11.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See R7 for impact and cost.	See R7 for impact and cost.	See R7 for impact and cost.		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 D.A 7.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - requirement D.A 7.3 - Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See R7 for impact and cost.	See R7 for impact and cost.	See R7 for impact and cost.		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 D.A 7.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See R7 for impact and cost.	See R7 for impact and cost.	See R7 for impact and cost.		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 D.A 7.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See R7 for impact and cost.	See R7 for impact and cost.	See R7 for impact and cost.		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R1	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	BC Hydro will need to develop a process to meet the requirement. Estimated ~$10,000 one time incremental cost.	10,000	0		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R2	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	BC Hydro will need to develop criteria to meet the requirement. Estimated ~$10,000 one time incremental cost.	10,000	0		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	BC Hydro will need to develop process and complete benchmark GMD Vulnerability assessment. Estimated ~$73,000 one time and ~$11,000 ongoing incremental cost.	73,000	11,000		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R6	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	GO, TO	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	BC Hydro will need to conduct a benchmark thermal impact assessment. Estimated ~$100,000 one time and ~$10,000 on going incremental cost.	100,000	10,000		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/ Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 R7 (R7.1, R7.2 only)	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Change to Part 7.3 Include a timetable, subject to approval for any extension sought under Part 7.4 for implementing the selected actions from part 7.1. Part 7.4 Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following : Part 7.4.1 Circumtances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how thoes circumtances are beyond the control of the responsible entity. Part 7.4.2 Remove requirement 7.4.2 in its entirety. Part 7.4.3 Added requirement 7.4.3 Part 7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	BC Hydro will need to develop and implement Corrective Action Plan (CAP). Unable to assess the one time and ongoing costs required mitigate issues and/or implement corrective action plans (CAPs) at this time as this is dependent on the results of the GMD Vulnerability Assessments. Estimated ~$220,000 one time and ~$5,000 ongoing incremental cost at minimum	220,000	5,000		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R8	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Delete requirement 8.3	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	BC Hydro will need to undertake supplemental study. Estimated ~$40,000 one time and ~$10,000 ongoing incremental cost.	40,000	10,000		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R9	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R10	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	GO, TO	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R11 (R11.1, R11.2 only)	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New Requirement	N/A	PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	Minimal incremental costs expected; negligible impact.	Minimal incremental costs expected	Minimal incremental costs expected		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R12	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	BC Hydro will need to develop and implement a process to obtain GIC data, including design, procurement, and installation of equipment to monitor GIC data. Estimated ~$1,020,000 one time and $5,000 on going incremental cost.	1,020,000	5,000		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.
TPL-007-4 R13	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA, PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	BC Hydro will need to implement a process to obtain geomagnetic field data. Estimated ~$8,000 one time and ~$5,000 ongoing incremental cost.	8,000	5,000		The first day of the first calendar quarter, six months after BCUC adoption and per a B.C. specific TPL-007-4 Implementation Plan.

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

BC Hydro (BA, RC, GO, TO, PA, GOP, TOP, RP, TP, TSP, DP):

Assessment Report Number	FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 8, 2020 Glossary of Terms	Acronym (If Applicable)	FERC Approved New/Revised/Retired NERC Term Definitions against Terms and Definitions listed in Columns "D" and "E" (changes to definition indicated by red text; deletions are not indicated)	Current BCUC Adopted Terms	Current BCUC Adopted Definition	FERC Approval Date of New/Revised/Retired NERC Term and Definition	Effective Date of New/ Revised/ Retired NERC Term and Definition in United States	Stakeholder Comments (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental Cost Associated with Revised/New Term and Definition, if any ($). (Press Alt-Enter to insert a carriage return in a cell)		BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time ($)	Cost Ongoing ($)	
10	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the PRC-010-2 standard which is held in abeyance in B.C., and is indirectly referenced from the PRC-006-4 (being assessed under the PC Assessment Report) via the term Special Protection System - SPS, as well as the currently adopted CIP-002-5.1a, EOP-004-4, FAC-010-3, FAC-011-3, IRO-005-3.1a, MOD-029-2a, MOD-030-3, NUC-001-3, NUC-001-4 (being assessed under the PC Assessment Report), PRC-001-1.1(ii), PRC-004-WECC-2, PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-2/4, TPL-001-4, and TPL-001-5.1 (being assessed under the PC Assessment Report)	**SPS**	See "Remedial Action Scheme"	Special Protection System (Remedial Action Scheme)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	23-Jun-16	01-Apr-17	No Impact.			
9	**Remedial Action Scheme** *Glossary term is specific to the PRC-010-2 standard which is held in abeyance in B.C., and is indirectly referenced from the PRC-006-4 (being assessed under the PC Assessment Report) via the term Special Protection System - SPS, as well as the currently adopted CIP-002-5.1a, EOP-004-4, FAC-010-3, FAC-011-3, IRO-005-3.1a, MOD-029-2a, MOD-030-3, NUC-001-3, NUC-001-4 (being assessed under the PC Assessment Report), PRC-001-1.1(ii), PRC-004-WECC-2, PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-2/4, TPL-001-4, and TPL-001-5.1 (being assessed under the PC Assessment Report)	**RAS**	A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as: • Meet requirements identified in the NERC Reliability Standards; • Maintain Bulk Electric System (BES) stability; • Maintain acceptable BES voltages; • Maintain acceptable BES power flows; • Limit the impact of Cascading or extreme events. The following do not individually constitute a RAS: a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays c. Out-of-step tripping and power swing blocking d. Automatic reclosing schemes e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage) k. Automatic sequences that proceed when manually initiated solely by a System Operator l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)	Remedial Action Scheme	See "Special Protection System"	19-Nov-15	01-Apr-17	No Impact.			
9	**Under Voltage Load Shedding Program** *Glossary term is specific to the new PRC-010-2 standard	**UVLS Program**	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate under voltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled under voltage-based load shedding is not included.	New	N/A	19-Nov-15	01-Apr-17	No Impact.			
10	**Geomagnetic Disturbance Vulnerability Assessment** *Glossary term is specific to TPL-007-4 Standard.	**GMD Vulnerability Assessment**	Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.	New	N/A	22-Sep-16	01-Jul-17	No Impact.			

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Planning Coordinator Assessment Report

Appendix C-2

Instructions for Registered Entities

INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS	
To Registered Entities – British Columbia Mandatory Reliability Standards Program,	
Please review each new and revised Standard (and corresponding redlines and mapping documents as available) as per the links provided from the BC Hydro Reliability website:	https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/reliability.html.
Complete the CIP Stnd Feedback and OPS Stnds Feedback (the yellow tab), and for each Standard assessed, please complete the following fields:	**A.** Insert the name and applicable functions of your registered entity at the top of the Survey Form as indicated by the **red text** in Row 2. **B.** Stakeholder Comments Organizational Activities and Reliability/Suitability Impact **(Column L)**: Please advise if there are no changes necessary to maintain compliance, or if changes are required, please describe a list of high-level incremental activities required to reach compliance. Please also indicate if there are any noted reliability/suitability impacts (technical or administrative) that could pose a challenge to potential adoption. Examples of suitability impacts: References made to unapproved standards, standard requirements depend on NERC approvals of data, undefined functional roles/responsibilities (i.e. Planning Coordinator), references to undefined processes/procedures, etc.. **C.** Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($) **(Columns M-O)**, if any associated with: - the adoption of a new Standard; or - a revision to a Standard compared to the immediately preceding version currently adopted by BCUC. Please indicate which costs are one-time versus ongoing, and ensure the assumptions associated with each estimate are captured in Column K. BC Hydro will use this information to develop recommendations to the BCUC regarding the potential impacts of each reliability Standard on registered entities for inclusion in the Report. **Column O** is intended for comments specifically related to those PC cost, while Column L is for other aspects of the impact such as reliability and activities as described above. **D.** BCUC Implementation Time **(Column P)**: Please include an assessment of the amount of time your organization would reasonably require to come into compliance with the Standard/requirement once adopted by the BCUC (i.e. 6 months from adoption, immediately after adoption, etc.). BC Hydro will use this information to recommend an overall implementation time for each Standard/requirement for inclusion in the Report. Regards, BC Hydro Reliability Compliance Department BCHydroReliabilityStandards@bchydro.com

GLOSSARY INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS		
To Registered Entities – British Columbia Mandatory Reliability Standards Program,		
Task #	**Task Description**	**Reference Files and Links**
1	Please review the NERC Glossary of Terms October 8, 2020 (hyperlinked in column C2), identified in the **Glossary Feedback** tab of this spreadsheet and fill out as follows: **IMPORTANT:** For tracking, when providing your comments please use this format: **First Name Last Name: Comment** **A**. in **Column I Stakeholder Comments** provide the list of activities (high-level) required to address the identified impacts **B**. **The Estimated Incremental Cost Associated with Revised/New Term/Definition (Columns J and K)**, if any associated with: - a revision to a Term/Definition compared to the version adopted by the BCUC; or - the adoption of a new Term/Definition. Please indicate which costs are one-time versus ongoing (in dollars $), and identify in **Column I** the assumptions associated with each estimate. **C**. in **Column L BCUC Implementation Time** provide an assessment of the time reasonably required to come into compliance with the Term's definition once adopted by the BCUC (i.e. 6 months from adoption, immediately after adoption etc). BC Hydro will use this information to recommend an overall implementation time for inclusion in the Report.	NERC Glossary of Terms Assessment 14/PC homepage - with archive
2	Compliance Leads are requested to email the Reliability Compliance department via BCHydroReliabilityStandards@bchydro.com when all feedback is complete.	BCHydroReliabilityStandards@bchydro.com

INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS	
To Registered Entities – British Columbia Mandatory Reliability Standards Program,	
Please review each new and revised Standard (and corresponding redlines and mapping documents as available) as per the links provided from the BC Hydro Reliability website:	https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/reliability.html.
Complete the CIP Stnd Feedback and OPS Stnds Feedback (the yellow tab), and for each Standard assessed, please complete the following fields:	**A.** Insert the name and applicable functions of your registered entity at the top of the Survey Form as indicated by the **red text** in Row 2. **B.** Stakeholder Comments Organizational Activities and Reliability/Suitability Impact **(Column L)**: Please advise if there are no changes necessary to maintain compliance, or if changes are required, please describe a list of high-level incremental activities required to reach compliance. Please also indicate if there are any noted reliability/suitability impacts (technical or administrative) that could pose a challenge to potential adoption. Examples of suitability impacts: References made to unapproved standards, standard requirements depend on NERC approvals of data, undefined functional roles/responsibilities (i.e. Planning Coordinator), references to undefined processes/procedures, etc.. **C.** Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($) **(Columns M-O)**, if any associated with: - the adoption of a new Standard; or - a revision to a Standard compared to the immediately preceding version currently adopted by BCUC. Please indicate which costs are one-time versus ongoing, and ensure the assumptions associated with each estimate are captured in Column K. BC Hydro will use this information to develop recommendations to the BCUC regarding the potential impacts of each reliability Standard on registered entities for inclusion in the Report. **Column O** is intended for comments specifically related to those PC cost, while Column L is for other aspects of the impact such as reliability and activities as described above. **D.** BCUC Implementation Time **(Column P)**: Please include an assessment of the amount of time your organization would reasonably require to come into compliance with the Standard/requirement once adopted by the BCUC (i.e. 6 months from adoption, immediately after adoption, etc.). BC Hydro will use this information to recommend an overall implementation time for each Standard/requirement for inclusion in the Report. Regards, BC Hydro Reliability Compliance Department BCHydroReliabilityStandards@bchydro.com

GLOSSARY INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS		
To Registered Entities – British Columbia Mandatory Reliability Standards Program,		
Task #	**Task Description**	**Reference Files and Links**
1	Please review the NERC Glossary of Terms October 8, 2020 (hyperlinked in column C2), identified in the **Glossary Feedback** tab of this spreadsheet and fill out as follows: **IMPORTANT:** For tracking, when providing your comments please use this format: **First Name Last Name: Comment** **A**. in **Column I Stakeholder Comments** provide the list of activities (high-level) required to address the identified impacts **B**. **The Estimated Incremental Cost Associated with Revised/New Term/Definition (Columns J and K)**, if any associated with: - a revision to a Term/Definition compared to the version adopted by the BCUC; or - the adoption of a new Term/Definition. Please indicate which costs are one-time versus ongoing (in dollars $), and identify in **Column I** the assumptions associated with each estimate. **C**. in **Column L BCUC Implementation Time** provide an assessment of the time reasonably required to come into compliance with the Term's definition once adopted by the BCUC (i.e. 6 months from adoption, immediately after adoption etc). BC Hydro will use this information to recommend an overall implementation time for inclusion in the Report.	NERC Glossary of Terms Assessment 14/PC homepage - with archive
2	Compliance Leads are requested to email the Reliability Compliance department via BCHydroReliabilityStandards@bchydro.com when all feedback is complete.	BCHydroReliabilityStandards@bchydro.com

From:	BCHydro Reliability Standards
To:	BCHydro Reliability Standards
Subject:	Planning Coordinator Assessment Report - Revised Consultation
Date:	2021, April 30 1:50:41 PM
Attachments:	Assessment Report PC Feedback Spreadsheet_External_April2021.xlsx PC Clean Standards April2021.pdf PC Redline Standards April2021.pdf

To Registered Entities in the British Columbia (**B.C.**) Mandatory Reliability Standards (**MRS**) Program:

BC Hydro, as the assessor on behalf of the province of British Columbia, is preparing the Planning Coordinator Assessment Report (**PC Report**) for filing with the BCUC. A key part of the assessment report process and input into the PC Report, is consultation with and feedback from all MRS registered entities with respect to the reliability impacts, suitability, potential costs and reliability standard applicability of adopting the standards being considered for adoption in B.C.

As you are aware, BC Hydro held its consultation with respect to the adoption of all reliability standards that the Federal Energy Regulatory Commission (**FERC**) had approved through November 30, 2020 that reference the PC function and/or reference other functional entities that may be impacted by a requirement referencing the PC (the **PC Standards**) with MRS registered entities ending on February 28, 2021.

In its preparation of the PC Report and since the closing of its consultation, a number of issues have come to BC Hydro's attention which may impact previous feedback provided. Specifically, and as described in more detail below, BC Hydro has: identified errors in the scope of the standards subject to assessment in the PC Report; identified corrections to some of the information provided in the PC Report Feedback Spreadsheet and materials; and, has received new information from BC Hydro (as MRS registered entity) with respect to its PC registration.

As such, and in an effort to provide all MRS registered entities with an opportunity to consider this new information, BC Hydro has determined that a short additional consultation process is required. Consistent with its previous practice, BC Hydro will provide a copy of all registered entities responses to the BCUC in its filing of the PC Report.

Scope of Consultation

1. **Change in PC Report Assumption - BC Hydro's PC Registration**: the PC Report assumption communicated with MRS registered entities in January 2021 was premised on "BC Hydro as the Planning Coordinator for its footprint and for those MRS Registered Entities interconnected to its footprint, aside from FortisBC; FortisBC as the Planning Coordinator for its footprint". Based on new information received from BC Hydro, this assessment assumption has now changed. BC Hydro as assessor understands that: BC Hydro intends to register for the PC function for BC Hydro's BES assets only and establish the PC function at BC Hydro. BC Hydro will continue to be the registered PA for its BES assets only.
   - At a future date, BC Hydro will consider the expansion of its PA and/or PC services to include other B.C. registered entities as defined by the reliability standards.

2. **Revised Scope of Standards Being Assessed**: the PC Report Feedback Spreadsheet originally included all reliability standards that the Federal Energy Regulatory Commission (**FERC**) had approved through November 30, 2020 that reference the PA or PC functions and/or reference other functional entities that may be impacted by a requirement referencing the PA or PC function.

   Several of the reliability standards included in the original PC Report Feedback Spreadsheet are already adopted and effective in B.C. as they are not solely dependent on the PA/PC function. As such, they are not subject to reassessment under the PC Report and BC Hydro was not required to seek feedback on those standards. Feedback received on these standards was included in the applicable prior Assessment Reports. Further, BC Hydro will not be assessing any feedback received with respect to those broader standards in the PC Report.

   As a result, BC Hydro has revised the PC Report Feedback Spreadsheet to include only those standards (or requirements) being assessed with PA and/or PC dependencies that FERC has approved through November 30, 2020 that are new or have been held in abeyance in B.C.; totaling 13 standards.

   NOTE: The footnote on page 1 of the B.C. version of the PRC-023-4 reliability standard included in the consultation package, makes a reference to the PRC-025-1 effective dates in the context of describing when the concurrently effective PRC-023-2 reliability standard will be superseded; specifically, circuits identified that meet Criterion 6 of PRC-023-2 Requirement 1. However, the PRC-025-1 reference has since been replaced with PRC-025-2. Entities should be aware of this change as they are reviewing both the PRC-023-2 and PRC-023-4 standards under the PC Report to provide feedback. BC Hydro has already advised the BCUC of this update in Assessment Report 14 and will be reiterating the same under the PC Report filing.

3. **Corrections to the PC Report Feedback Spreadsheet and materials:** after concluding its consultation, BC Hydro identified four corrections to the feedback spreadsheet and associated materials as follows:
   - The PRC-023-2 reliability standard which is adopted and currently effective in B.C. contains requirements (R1.0-R5.0 for circuits 4.2.1.2, 4.2.1,3, 4.2.1.5 and 4.2.1.6 that meet Criterion 6 of R1.0 as identified by the PC function pursuant to R6.0) with sole PA/PC dependencies that were held in abeyance was mistakenly omitted.
   - The TPL-001-4 reliability standard which is adopted and currently effective in B.C. contains a requirement (R7.0) with sole PA/PC dependencies that was held in abeyance was mistakenly omitted.
   - The EOP-003-2 reliability standard was mischaracterized as being retired. This standard was previously held in abeyance in B.C. and hence cannot be retired as it was never adopted. EOP-003-2 is superseded by the PRC-010-2 reliability standard also held in abeyance in B.C. PRC-010-2 is also being assessed under the PC Report.
   - The North American Electric Reliability Corporation (**NERC**) Glossary term Geomagnetic Disturbance Vulnerability Assessment (associated with the TPL-007-4 reliability standard being assessed under the PC Report) was mistakenly omitted.

   The revised feedback form also reflects these corrections.

Next Steps

With the changes noted above MRS registered entities are asked to:

1. Complete the attached revised PC Report Feedback Spreadsheet in replacement of your previously submitted form; or
2. Instruct us to use your original PC Report Feedback Spreadsheet if you have no further feedback.

Deadlines

Please note, all feedback is due end of day Friday May 14, 2021.

Instructions

Task	Description	Comments
1. Review revised PC Report Materials	Review the PC standards (new and held in abeyance) and the Glossary of Terms on the BC Hydro attached and as available on the Reliability site.	
2. Provide Feedback on PC Report	You have two options: 1. Complete the attached revised PC Report Feedback Spreadsheet in replacement of your previously submitted form; or **2.** Instruct us to use your original PC Report Feedback Spreadsheet if you have no further feedback.	If we do not hear back from you by the deadline, we will assume you have selected option 2.
3. Email your feedback	Email your completed feedback to the **BC Hydro Reliability Standards Team** at BCHydroReliabilityStandards@bchydro.com	For assistance or any questions, please email BCHydroReliabilityStandards@bchydro.com.

to the BC Hydro Reliability Standards Team	**Due: end of day Friday May 14, 2021**	
4. Q&A Call Details	Wednesday May 5, 2021 2:00 – 3:00 pm	Microsoft Teams meeting **Join on your computer or mobile app** **Click here to join the meeting** **Or call in (audio only)** +1 604-343-0415,,293285721# Canada, Vancouver Phone Conference ID: 293 285 721# Find a local number | Reset PIN

-

If you have questions with respect to the scope of consultation and revised feedback form, BC Hydro will be hosting a Q&A on Wednesday May 5th at 2:00 – 3:00 pm.

Otherwise, please contact: BCHydroReliabilityStandards@bchydro.com

Regards,

BC Hydro Reliability Standards & Assurance

<table>
<tr><th colspan="2">INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS</th></tr>
<tr><td colspan="2">To Registered Entities – British Columbia Mandatory Reliability Standards Program,</td></tr>
<tr><td>Please review each new and revised Standard (and corresponding redlines and mapping documents as available) as per the links provided from the BC Hydro Reliability website:</td><td>https://www.bchydro.com/energy-in-bc/operations/transmission/transmission-system/reliability.html.</td></tr>
<tr><td>Complete the PC Stnds Feedback (the yellow tab), and for each Standard assessed, please complete the following fields:</td><td>A. Insert the name and applicable functions of your registered entity at the top of the Survey Form as indicated by the red text in Row 2.

B. Stakeholder Comments Organizational Activities and Reliability/Suitability Impact (Column L): Please advise if there are no changes necessary to maintain compliance, or if changes are required, please describe a list of high-level incremental activities required to reach compliance. Please also indicate if there are any noted reliability/suitability impacts (technical or administrative) that could pose a challenge to potential adoption. Examples of suitability impacts: References made to unapproved standards, standard requirements depend on NERC approvals of data, undefined functional roles/responsibilities (i.e. Planning Coordinator), references to undefined processes/procedures, etc..

C. Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($) (Columns M-O), if any associated with:
- the adoption of a new Standard; or
- a revision to a Standard compared to the immediately preceding version currently adopted by BCUC.

Please indicate which costs are one-time versus ongoing, and ensure the assumptions associated with each estimate are captured in Column K. BC Hydro will use this information to develop recommendations to the BCUC regarding the potential impacts of each reliability Standard on registered entities for inclusion in the Report.

Column O is intended for comments specifically related to those PC cost, while Column L is for other aspects of the impact such as reliability and activities as described above.

D. BCUC Implementation Time (Column P):
Please include an assessment of the amount of time your organization would reasonably require to come into compliance with the Standard/requirement once adopted by the BCUC (i.e. 6 months from adoption, immediately after adoption, etc.). BC Hydro will use this information to recommend an overall implementation time for each Standard/requirement for inclusion in the Report.

E. Registered Entities are requested to email the Reliability Compliance department via BCHydroReliabilityStandards@bchydro.com when all feedback is complete.

Regards,

BC Hydro Reliability Compliance Department
BCHydroReliabilityStandards@bchydro.com</td></tr>
</table>

GLOSSARY INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS	
Task Description	**Reference Files and Links**
Please review the NERC Glossary of Terms October 8, 2020 (hyperlinked in column C2), identified in the **Glossary Feedback** tab of this spreadsheet and fill out as follows: **Important: Insert the name and applicable functions of your registered entity at the top of the Survey Form as indicated by the red text in Row 2.** **A**. in **Column I Stakeholder Comments** provide the list of activities (high-level) required to address the identified impacts **B**. **The Estimated Incremental Cost Associated with Revised/New Term/Definition (Columns J and K)**, if any associated with: - a revision to a Term/Definition compared to the version adopted by the BCUC; or - the adoption of a new Term/Definition. Please indicate which costs are one-time versus ongoing (in dollars $), and identify in **Column I** the assumptions associated with each estimate. **C**. in **Column L BCUC Implementation Time** provide an assessment of the time reasonably required to come into compliance with the Term's definition once adopted by the BCUC (i.e. 6 months from adoption, immediately after adoption etc). BC Hydro will use this information to recommend an overall implementation time for inclusion in the Report.	NERC Glossary of Terms
Registered Entities are requested to email the Reliability Compliance department via BCHydroReliabilityStandards@bchydro.com when all feedback is complete.	BCHydroReliabilityStandards@bchydro.com

BC Hydro
Power smart

BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

Appendix C-3

External Stakeholder Feedback

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
CIP-002-5.1a R1	CIP-002-5.1a RSAW	**Cyber Security — BES Cyber System Categorization** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.	CIP-002-5.1a Adopted 2018 Assessment Report 11 R-33-18	CIP-002-5.1 Adpoted 2015 Assessment Report 8 R-38-15	No Redline	N/A	PA/PC	Docket No. RD17-2-000 Issued December 27, 2016	27-Dec-2016	CIP-002-5.1a Implementation Plan Implementation Time: 24 Months Minimum US Enforcement Date 21-Dec-2016	No incremental changes expected.				n/a - standard is already enforceable.
CIP-014-2 R2	CIP-014-2 RSAW	**Physical Security** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.	CIP-014-2 Adopted 2016 Assessment Report 9 R-32-16A	None - CIP-014-2 was new standard	New Standard N/A	CIP-014-2 Mapping Document	PA/PC	Docket No. RD15-4-000 Issued July 14, 2015	2-Oct-2015	CIP-014-2 Implementation Plan Implementation Time: CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved. US Enforcement Date 10-Feb-2015	No comments as this standard is not applicable to our entity.				
EOP-003-2 R2	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Plans needed for automatic load shedding for underfrequency or undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2 Mapping Document	PA/PC	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	No comments as this standard is not applicable to our entity.				
EOP-003-2 R4	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	PA/PC	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	No comments as this standard is not applicable to our entity.				
EOP-003-2 R7	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	PA/PC	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	No comments as this standard is not applicable to our entity.				
FAC-002-3 R1	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
FAC-002-3 R2	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No incremental changes expected. However, it should be noted that it is impractical for entities to assess the impact of the PC function in relation to any standard or requirement when the structure and processes of the proposed PC are unknown.				One year from the date that Planning Coordinator registration takes effect.
FAC-002-3 R3	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. Remove Applicability Load Serving Entity	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No incremental changes expected. However, it should be noted that it is impractical for entities to assess the impact of the PC function in relation to any standard or requirement when the structure and processes of the proposed PC are unknown.				One year from the date that Planning Coordinator registration takes effect.
FAC-002-3 R4	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
FAC-002-3 R5	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No incremental changes expected. However, it should be noted that it is impractical for entities to assess the impact of the PC function in relation to any standard or requirement when the structure and processes of the proposed PC are unknown.				One year from the date that Planning Coordinator registration takes effect.
FAC-008-3 R7	FAC-008-3 RSAW	**Facility Ratings** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.	FAC-008-3 Adopted 2014 Assessment Report 7 R-32-14	FAC-008-1 and FAC-009-1 No Assessment Report	3. Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities.	N/A	PA/PC	Docket No. RD11-10-000 Issued Nov 17, 2011	17-Nov-2011	FAC-008-3 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved. US Enforcement Date 01-Jan-2013	No incremental changes expected.				n/a - standard is already enforceable.
FAC-008-3 R8	FAC-008-3 RSAW	**Facility Ratings** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.	FAC-008-3 Adopted 2014 Assessment Report 7 R-32-14	FAC-008-1 and FAC-009-1 No Assessment Report	3. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), 12 Such as temporary de-ratings of impaired equipment in accordance with good utility practice. Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s)	N/A	PA/PC	Docket No. RD11-10-000 Issued Nov 17, 2011	17-Nov-2011	FAC-008-3 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved. US Enforcement Date 01-Jan-2013	No incremental changes expected.				n/a - standard is already enforceable.
FAC-010-3 R1	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
FAC-010-3 R2	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
FAC-010-3 R3	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. Removal of special protection systems in R3.4	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
FAC-010-3 R4	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
FAC-011-3 R3	FAC-011-3 RSAW	**System Operating Limits Methodology for the Operations Horizon** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-11-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-011-2 Adopted 2010 Assessment Report 2 G-167-10	3. Updated with definition and implementation of Remedial Action Scheme		PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-011-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
FAC-011-3 R4	FAC-011-3 RSAW	**System Operating Limits Methodology for the Operations Horizon** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-11-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-011-2 Adopted 2010 Assessment Report 2 G-167-10	3. No changes to the requirement from previous version.		PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-011-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
FAC-014-2 R3	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	No comments as this requirement is not applicable to our entity.				
FAC-014-2 R4	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	No comments as this requirement is not applicable to our entity.				
FAC-014-2 R5	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	No comments as this requirement is not applicable to our entity.				
FAC-014-2 R6	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	No comments as this requirement is not applicable to our entity.				
IRO-017-1 R3	IRO-017-1 RSAW	**Outage Coordination** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	IRO-017-1 Adopted 2017 Assessment Report 10 R-39-17	None - IRO-017-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-16-000 Issued Nov 19, 2015	26-Jan-2016	IRO-017-1 Implementation Plan Implementation Time: Twelve month implementation period US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
IRO-017-1 R4	IRO-017-1 RSAW	**Outage Coordination** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	IRO-017-1 Adopted 2017 Assessment Report 10 R-39-17	None - IRO-017-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-16-000 Issued Nov 19, 2015	26-Jan-2016	IRO-017-1 Implementation Plan Implementation Time: Twelve month implementation period US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
MOD-001-1a R4	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	No comments as this requirement is not applicable to our entity.				
MOD-001-1a R5	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	No comments as this requirement is not applicable to our entity.				
MOD-001-1a R9	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	No comments as this requirement is not applicable to our entity.				
MOD-004-1 R2	MOD-004-1 RSAW	**Capacity Benefit Margin** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	MOD-004-1	MOD-004-1 Apdopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-004-1 Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	No comments as this requirement is not applicable to our entity.				
MOD-004-1 R9	MOD-004-1 RSAW	**Capacity Benefit Margin** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	MOD-004-1	MOD-004-1 Apdopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-004-1 Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	No comments as this requirement is not applicable to our entity.				

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
MOD-008-1 R3	MOD-008-1 RSAW	**Transmission Reliability Margin Calculation Methodology** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.	MOD-008-1	MOD-008-1 Apdopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-008-1 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	**No comments as this requirement is not applicable to our entity.**				
MOD-031-3 R1	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - Remove applicability Load Serving Entity	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
MOD-031-3 R2	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
MOD-031-3 R3	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
MOD-031-3 R4	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
MOD-032-1 R1	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. Added entities responsible for providing the data in R1.3	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implemenatation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	**No comments as this requirement is not applicable to our entity.**				
MOD-032-1 R2	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implemenatation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	**The compliance activities required will depend greatly on the level of detail in which generator equipment is required to be described by the TP/PC. If the process aligns with existing BC Hydro processes for generator interconnection and model validation, minimal incremental impacts and costs are anticipated. If the process requires the development of new models for complex equipment such as wind turbine generators and STATCOMs, specialist engineering resources will be required.**	50,000		Upper end estimate for development of updated generic plant models.	Two years from the date of adoption by BCUC.
MOD-032-1 R3	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implemenatation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	**No incremental changes expected.**				Two years from the date of adoption by BCUC.
MOD-032-1 R4	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implemenatation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	**No comments as this requirement is not applicable to our entity.**				
MOD-033-2 R1	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
MOD-033-2 R2	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
NUC-001-4 ALL Requirements	RSAW Not on NERC	**Nuclear Plant Interface Coordination** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.	NUC-001-3	N/A	N/A	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	NUC-001-4 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
PRC-006-4 DB1	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
PRC-006-4 DB11	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				

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INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.):					Cape Scott Wind LP (GO/GOP)										
FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 DB12	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 DB2	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 DB3	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 DB4	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R11	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R12	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R13	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R14	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R15	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R1	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R2	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R3	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - Update reference to PRC-006-4	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R4	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - Update reference to PRC-006-4	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R5	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R6	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				
PRC-006-4 R7	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	No comments as this requirement is not applicable to our entity.				

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 R8	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
PRC-006-4 R9	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
PRC-006-4 R10	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R1	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R2	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R3	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R4	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Added subpoints: 4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and 4.2. The performance (i.e., operation and non operation) of the UVLS Program equipment.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R5	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Removed deficiencies in its UVLS Program	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R6	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R7	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-010-2 R8	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**No comments as this requirement is not applicable to our entity.**				
PRC-012-2 R1	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	**No incremental changes expected.**				36 months from the date of adoption by the BCUC.
PRC-012-2 R2	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	**No comments as this requirement is not applicable to our entity.**				
PRC-012-2 R4	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Abeyance Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	**No comments as this requirement is not applicable to our entity.**				

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INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-023-4 R3	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
PRC-023-4 R4	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
PRC-023-4 R6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	No comments as this requirement is not applicable to our entity.				
PRC-024-3 R3	RSAW N/A	**Title: Frequency and Voltage Protection Settings for Generating Resources** To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).	PRC-024-2 PRC-024-3 is being assessed on Assessment 14	PRC-024-2 Adopted 2016 Assessment Report 9 R-32-16	3 - Each Generator Owner shall document each known regulatory or equipment limitation that prevents an applicable generating resource(s) with frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. 3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following: • Identification of a regulatory or equipment limitation. • Repair of the equipment causing the limitation that removes the limitation. • Replacement of the equipment causing the limitation with equipment that removes the limitation. • Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.	N/A	PA/PC	Docket No. RD20-7-000 Issued July 9, 2020 Publish Date TBA	Comments on the collection of information are due September 29, 2020.	PRC-024-3 Implementation Plan Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. US Enforcement Date of Standard: 01-Oct-2022	No incremental changes expected.				24 months after the date of adoption by the BCUC.
PRC-024-3 R4	RSAW N/A	**Title: Frequency and Voltage Protection Settings for Generating Resources** To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).	PRC-024-2 PRC-024-3 is being assessed on Assessment 14	PRC-024-2 Adopted 2016 Assessment Report 9 R-32-16	3 - Each Generator Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required.	N/A	PA/PC	Docket No. RD20-7-000 Issued July 9, 2020 Publish Date TBA	Comments on the collection of information are due September 29, 2020.	PRC-024-3 Implementation Plan Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. US Enforcement Date of Standard: 01-Oct-2022	No incremental changes expected.				24 months after the date of adoption by the BCUC.
PRC-026-1 R1	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	A challenge for potential adoption of this standard is that BC Hydro does not currently provide event analysis reports to other BC registered entities except to the extent required by other reliability standards. It will be difficult if not impossible for entities to become aware of stable or unstable power swings that may have occurred in their area (R2.2) without the assistance of BC Hydro. The lack of a BC-wide Event Analysis program reduces the reliability benefit of this standard, since entities operate with minimal visibility of wide-area events on the BES. The intended role of the PC in regard to event analysis within its footprint is a matter that could be addressed through stakeholder consultation.				12 months after the date of adoption by the BCUC.
PRC-027-1 R1	RSAW Not on NERC	**Coordination of Protection Systems for Performance During Faults** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PRC-027-1 Future Effective Assessment Report 12 R-21-19	PRC-001-1.1(ii) Adopted 2016 Assessment Report 9 R-38-15	1. Merging of all R1.3.3 sub clauses	PRC-027-1 Mapping Document	PA/PC	Docket No. RM16-22-000 Issued Jun 7, 2018	13-Aug-2018	PRC-027-1 Implementation Plan Implementation Time: PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved US Enforcement Date 01-Apr-2021	No incremental changes expected.				No change to existing enforcement date.
PRC-027-1 R2	RSAW Not on NERC	**Coordination of Protection Systems for Performance During Faults** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PRC-027-1 Future Effective Assessment Report 12 R-21-19	PRC-001-1.1(ii) Adopted 2016 Assessment Report 9 R-38-15	1. Added BES to Option 2	PRC-027-1 Mapping Document	PA/PC	Docket No. RM16-22-000 Issued Jun 7, 2018	13-Aug-2018	PRC-027-1 Implementation Plan Implementation Time: PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved US Enforcement Date 01-Apr-2021	No incremental changes expected.				No change to existing enforcement date.
TPL-001-5.1 R1	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Updated requirement body to reference MOD-032 Part 1.1.2 and subparts have been deleted	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-001-5.1 R2	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 2.1.4 moved to Part 2.1.3. A properly planned Transmission system should facilitate maintenance outages without Non Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL 001 5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4. Part 2.1.5 Document internal conforming as reflecting in R2, Part 2.4.5 Part 2.4.3 has been moved back to 2.4.3 as it was in TPL 001 4. Part 2.4.4 TPL 001 4, Part 2.4.3 moved to TPL 001 5, Part 2.4.4 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4. Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy. Part 2.7 Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard. Part 2.7 Updated to reflect NERC Glossary Term	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-001-5.1 R3	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 3.2 Document internal conforming clean up to move the last sentence of Requirement R3, Part 3.5 to Requirement R3, Part 3.2.	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-001-5.1 R4	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 4.1.1 Updated to reflect NERC Glossary Term Part 4.2 Prior to this change, TPL 001 4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL 001 4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-001-5.1 R5	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-001-5.1 R6	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-001-5.1 R7	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-001-5.1 R8	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	No comments as this requirement is not applicable to our entity.				
TPL-007-4 D.A 11.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 D.A 11.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 D.A 11.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 D.A 7.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - requirement D.A 7.3 - Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 D.A 7.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 D.A 7.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R1	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R2	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	No comments as this requirement is not applicable to our entity.				

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): Cape Scott Wind LP (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 R4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R6	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R7	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Change to Part 7.3 Include a timetable, subject to approval for any extension sought under Part 7.4 for implementing the selected actions from part 7.1. Part 7.4 Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following : Part 7.4.1 Circumtances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how thoes circumtances are beyond the control of the responsible entity. Part 7.4.2 Remove requirement 7.4.2 in its entirety. Part 7.4.3 Added requirement 7.4.3 Part 7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R8	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Delete requirement 8.3	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R9	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R10	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R11	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New Requirement	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R12	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	No comments as this requirement is not applicable to our entity.				
TPL-007-4 R13	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	No comments as this requirement is not applicable to our entity.				

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

INSERT YOUR ENTITY NAME AND FUNCTIONAL REGISTRATIONS APPLICABLE TO YOUR ENTITY (i.e. TO, DP, GO, etc.): **Cape Scott Wind LP (GO/GOP)**

Assessment Number	FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 8, 2020 Glossary of Terms	Acronym (If Applicable)	FERC Approved New/Revised/Retired NERC Term Definitions against Terms and Definitions listed in Columns "D" and "E" (changes to definition indicated by red text; deletions are not indicated)	Current BCUC Adopted Terms from October 8, 2020 Glossary of Terms	Current BCUC Adopted Definition from October 8, 2020 Glossary of Terms	FERC Approval Date of New/Revised/Retired NERC Term and Definition	Effective Date of New/Revised/Retired NERC Term and Definition in United States	Stakeholder Comments (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental Cost Associated with Revised/New Term and Definition, if any ($). (Press Alt-Enter to insert a carriage return in a cell)		BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time ($)	Cost Ongoing ($)	
11	**Remedial Action Scheme** *Glossary term is specific to the currently adopted CIP-002-3/5.1, CIP-003-5, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, EOP-004-3, FAC-010-3, FAC-011-3, MOD-029-2a, MOD-030-3, NUC-001-3, PRC-001-1.1(ii), PRC-004-5(i), PRC-004-WECC-2, PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-4, PRC-024-2, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a standards	**RAS**	N/A	**Retired**	See "Special Protection System"	31-Mar-2017	31-Mar-2017				
11	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the currently adopted CIP-002-3/5.1, CIP-003-5, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, CIP-011-2, EOP-004-3, FAC-010-3, FAC-011-3, IRO-002-4, IRO-005-3.1a, IRO-008-2, IRO-010-2, MOD-029-2a, MOD-030-3, PRC-001-1.1(ii), PRC-004-5(i), PRC-005-2(i), PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-2, PRC-023-4, PRC-024-2, PRC-025-1, TOP-001-3, TOP-002-4, TOP-003-3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a standards	**SPS**	N/A	**Retired**	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	31-Mar-2017	31-Mar-2017				
10	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the PRC-010-2 standard which is held in abeyance in B.C., and is indirectly referenced from the PRC-006-2 (also held in abeyance in B.C.) via the term Special Protection System - SPS, as well as the currently adopted CIP-002-3/5.1, EOP-004-2, FAC-010-2.1, FAC-011-2, IRO-005-3.1a, MOD-029-1a, MOD-030-2, NUC-001-2/3, PRC-001-1.1, PRC-004-WECC-1, PRC-005-2(i), PRC-015-0, PRC-016-0.1, PRC-017-0, PRC-021-1, PRC-023-1/2/3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a	**SPS**	See "Remedial Action Scheme"	Special Protection System (Remedial Action Scheme)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	23-Jun-16	01-Apr-17				
9	**Remedial Action Scheme** *Glossary term is specific to the new PRC-010-2 standard, and is indirectly referenced from the new PRC-006-2 and PRC-005-2(i) standards (via the term Special Protection System - SPS) as well as the currently adopted CIP-002-3/5.1, EOP-004-2, FAC-010-2.1, FAC-011-2, IRO-005-3.1a, MOD-029-1a, MOD-030-2, NUC-001-2/3, PRC-001-1.1, PRC-004-WECC-1, PRC-015-0, PRC-016-0.1, PRC-017-0, PRC-021-1, PRC-023-1/2/3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a	**RAS**	Please refer to the NERC Glossary of Terms for the definition as it is too long to replicate here.	**Remedial Action Scheme**	"See Special Protection System" which is defined as: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	19-Nov-15	01-Apr-17				
9	**Under Voltage Load Shedding Program** *Glossary term is specific to the new PRC-010-2 standard	**UVLS Program**	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate under voltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled under voltage-based load shedding is not included.	**New**	N/A	19-Nov-15	01-Apr-17				

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.															
FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)															
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
CIP-002-5.1a R1	CIP-002-5.1a RSAW	**Cyber Security — BES Cyber System Categorization** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.	CIP-002-5.1a Adopted 2018 Assessment Report 11 R-33-18	CIP-002-5.1 Adpoted 2015 Assessment Report 8 R-38-15	No Redline	N/A	PA/PC	Docket No. RD17-2-000 Issued December 27, 2016	27-Dec-2016	CIP-002-5.1a Implementation Plan Implementation Time: 24 Months Minimum US Enforcement Date 21-Dec-2016	BC Hydro could designate FortisBC or other registered entity generating facilities as a medium impact facility under impact rating criteria 2.3, if it is necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year. It is currently unknown if BC Hydro would designate a FortisBC generating facility as medium impact. If no FortisBC generation facilities are designated as medium impact by BC Hydro there would be no cost increase. FortisBC has not currently designated a generating facility as a medium impact facility under impact rating criteria 2.3 as a TP and this analysis would not change if FortisBC was also registered as a PC. Also, there are no FortisBC generation facilities currently rated as medium impact.	$0 - Unknown No additional costs	$0 - Unknown No additional costs	FortisBC cannot estimate any costs to apply the CIP medium impact requirements without knowing the specific generation facilities affected. N/A	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date immediately after BCUC approval.
CIP-014-2 R2	CIP-014-2 RSAW	**Physical Security** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.	CIP-014-2 Adopted 2016 Assessment Report 9 R-32-16A	None - CIP-014-2 was new standard	New Standard N/A	CIP-014-2 Mapping Document	PA/PC	Docket No. RD15-4-000 Issued July 14, 2015	2-Oct-2015	CIP-014-2 Implementation Plan Implementation Time: CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved. US Enforcement Date 10-Feb-2015	This requirement allows Transmission Owners (TO) to select an unaffiliated third party, which could be a PC, TP, or RC, to verify the TO risk assessment.	No additional costs	No additional costs	BC Hydro or FortisBC registering as a PC does not impact costs identified for CIP-014 under previous assessment reports.	Recommended effective date immediately after BCUC approval.
EOP-003-2 R2	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Plans needed for automatic load shedding for underfrequency or undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2 Mapping Document	PA/PC	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	This standard has been inactive or retired in the US since March 31, 2017. The previous revision to this standard (EOP-003-1) has been expired or retired in BC since September 30, 2018. Therefore, FortisBC recommends that this standard be retired in BC.	No additional costs	No additional costs	N/A	Recommended retirement date immediately after BCUC approval.
EOP-003-2 R4	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	PA/PC	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	See EOP-003-2 R2	See EOP-003-2 R2	See EOP-003-2 R2	See EOP-003-2 R2	See EOP-003-2 R2
EOP-003-2 R7	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	PA/PC	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	See EOP-003-2 R2	See EOP-003-2 R2	See EOP-003-2 R2	See EOP-003-2 R2	See EOP-003-2 R2
FAC-002-3 R1	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Coordination with BC Hydro as the PC would be required for new generation, transmission, or load facilities connected to the Bulk Electric System. The data submittal and study coordination is applicable to TP, TO, GO, and DP registered entities. BC Hydro has not provided a process or requirements for FortisBC coordination on new facilities. All requirements are applicable to both TP and PC, therefore, FortisBC is already required to be compliant with this standard as a TP. Minimal changes are required to current documentation and processes if FortisBC also registers as a PC.	Unknown No additional costs	Unknown No additional costs	FortisBC cannot estimate any costs without knowing the BC Hydro data submittal and study requirements. N/A	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date immediately after BCUC approval.
FAC-002-3 R2	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1
FAC-002-3 R3	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. Remove Applicability Load Serving Entity	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1
FAC-002-3 R4	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1
FAC-002-3 R5	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1	See FAC-002-3 R1
FAC-008-3 R7	FAC-008-3 RSAW	**Facility Ratings** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.	FAC-008-3 Adopted 2014 Assessment Report 7 R-32-14	FAC-008-1 and FAC-009-1 No Assessment Report	3. Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities.	N/A	PA/PC	Docket No. RD11-10-000 Issued Nov 17, 2011	17-Nov-2011	FAC-008-3 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved. US Enforcement Date 01-Jan-2013	FortisBC already provides facility ratings documentation to BC Hydro after each revision. BC Hydro has not currently requested any change to this process or the documentation. As long as BC Hydro does not request a new process or documentation to be completed if they register as the provincial PC, then BC Hydro or FortisBC registering as a PC does not impact costs identified for FAC-008 under previous assessment reports.	No additional costs	No additional costs	N/A	Recommended effective date immediately after BCUC approval.

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

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FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
FAC-008-3 R8	FAC-008-3 RSAW	**Facility Ratings** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.	FAC-008-3 Adopted 2014 Assessment Report 7 R-32-14	FAC-008-1 and FAC-009-1 No Assessment Report	3. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), 12 Such as temporary de-ratings of impaired equipment in accordance with good utility practice. Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s)	N/A	PA/PC	Docket No. RD11-10-000 Issued Nov 17, 2011	17-Nov-2011	FAC-008-3 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved. US Enforcement Date 01-Jan-2013	**See FAC-008-3 R7**	**See FAC-008-3 R7**	**See FAC-008-3 R7**	**See FAC-008-3 R7**	**See FAC-008-3 R7**
FAC-010-3 R1	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	**See FAC-014-2 R4** **FortisBC will need to develop a new System Operating Limit (SOL) Methodology for use in developing SOLs within the FortisBC BES footprint.**	**See FAC-014-2 R4** **$5,000 - $10,000**	**See FAC-014-2 R4** **No additional costs**	**See FAC-014-2 R4** **N/A**	**See FAC-014-2 R4** **Recommended effective date is 24-36 months after BCUC approval.**
FAC-010-3 R2	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**
FAC-010-3 R3	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. Removal of special protection systems in R3.4	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**
FAC-010-3 R4	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**	**See FAC-010-3 R1**
FAC-011-3 R3	FAC-011-3 RSAW	**System Operating Limits Methodology for the Operations Horizon** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-11-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-011-2 Adopted 2010 Assessment Report 2 G-167-10	3. Updated with definition and implementation of Remedial Action Scheme		PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-011-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	**See FAC-014-2 R6**	**See FAC-014-2 R6**	**See FAC-014-2 R6**	**See FAC-014-2 R6**	**See FAC-014-2 R6**
FAC-011-3 R4	FAC-011-3 RSAW	**System Operating Limits Methodology for the Operations Horizon** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-11-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-011-2 Adopted 2010 Assessment Report 2 G-167-10	3. No changes to the requirement from previous version.		PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-011-3 Implementation Plan Impelmentation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	**This requirement specifies that the RC must issue its SOL Methodology to each PC and TP that models any portion of the RC Area.**	**No additional costs**	**No additional costs**	**N/A**	**Recommended effective date immediately after BCUC approval.**
FAC-014-2 R3	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000, Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	**See FAC-014-2 R4**	**See FAC-014-2 R4**	**See FAC-014-2 R4**	**See FAC-014-2 R4**	**See FAC-014-2 R4**
FAC-014-2 R4	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000, Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	**It is currently unknown if BC Hydro would require FortisBC to complete new or additional SOL studies for the FortisBC TP area as defined in the BC Hydro PC SOL Methodology document and process.** **FortisBC will be required to establish SOLs, including Interconnection Reliability Operating Limits (IROLs), for the FortisBC BES footprint that are consistent with the new FortisBC SOL Methodology on an annual basis.**	**Unknown** **See FAC-010-3 R1**	**Unknown** **$5,000 - $10,000**	**FortisBC cannot estimate any costs without knowing the BC Hydro SOL requirements.** **N/A**	**Recommended effective date is 24-36 months after BCUC approval.** **Recommended effective date is 24-36 months after BCUC approval.**
FAC-014-2 R5	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000, Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	**See FAC-014-2 R4**	**See FAC-014-2 R4**	**See FAC-014-2 R4**	**See FAC-014-2 R4**	**See FAC-014-2 R4**
FAC-014-2 R6	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000, Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	**This requirements specifies that the PC shall provide a list of multiple contingencies and the associated stability limits to the RC that monitor the facilities associated with these contingencies and limits. BC Hydro and FortisBC already provide multiple contingency and SOL lists to the RC under other standards and functional registrations.**	**No additional costs**	**No additional costs**	**N/A**	**See FAC-014-2 R4**
IRO-017-1 R3	IRO-017-1 RSAW	**Outage Coordination** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	IRO-017-1 Adopted 2017 Assessment Report 10 R-39-17	None - IRO-017-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-16-000, Issued Nov 19, 2015	26-Jan-2016	IRO-017-1 Implementation Plan Implementation Time: Twelve month implementation period US Enforcement Date 01-Apr-2017	**These requirements are applicable to both TP and PC, therefore, BC Hydro and FortisBC are already required to be compliant with this standard as TPs. No changes are required to current documentation and processes if BC Hydro or FortisBC register as a PC.**	**No additional costs**	**No additional costs**	**N/A**	**Recommended effective date immediately after BCUC approval.**
IRO-017-1 R4	IRO-017-1 RSAW	**Outage Coordination** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	IRO-017-1 Adopted 2017 Assessment Report 10 R-39-17	None - IRO-017-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-16-000, Issued Nov 19, 2015	26-Jan-2016	IRO-017-1 Implementation Plan Implementation Time: Twelve month implementation period US Enforcement Date 01-Apr-2017	**See IRO-017-1 R3**	**See IRO-017-1 R3**	**See IRO-017-1 R3**	**See IRO-017-1 R3**	**See IRO-017-1 R3**

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FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
MOD-001-1a R4	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	**BC Hydro and FortisBC already provide their Available Transfer Capability Implementation Documents (ATCID) to each other as required under other functional registrations. No changes are required to current documentation and processes if BC Hydro or FortisBC register as a PC.**	**No additional costs**	**No additional costs**	**N/A**	**Recommended effective date immediately after BCUC approval.**
MOD-001-1a R5	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	**See MOD-001-1a R4**	**See MOD-001-1a R4**	**See MOD-001-1a R4**	**See MOD-001-1a R4**	**See MOD-001-1a R4**
MOD-001-1a R9	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	**See MOD-001-1a R4**	**See MOD-001-1a R4**	**See MOD-001-1a R4**	**See MOD-001-1a R4**	**See MOD-001-1a R4**
MOD-004-1 R2	MOD-004-1 RSAW	**Capacity Benefit Margin** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	MOD-004-1	MOD-004-1 Apdopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-004-1 Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	**BC Hydro and FortisBC already provide their Capacity Benefit Margin Implementation Documents (CBMID) to each other as required under other functional registrations. No changes are required to current documentation and processes if BC Hydro or FortisBC register as a PC.**	**No additional costs**	**No additional costs**	**N/A**	**Recommended effective date immediately after BCUC approval.**
MOD-004-1 R9	MOD-004-1 RSAW	**Capacity Benefit Margin** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	MOD-004-1	MOD-004-1 Apdopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-004-1 Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	**See MOD-004-1 R2**	**See MOD-004-1 R2**	**See MOD-004-1 R2**	**See MOD-004-1 R2**	**See MOD-004-1 R2**
MOD-008-1 R3	MOD-008-1 RSAW	**Transmission Reliability Margin Calculation Methodology** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.	MOD-008-1	MOD-008-1 Apdopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	PA/PC	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-008-1 Implemenation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	**BC Hydro and FortisBC already provide their Transmission Reliability Margin Implementation Documents (TRMID) to each other as required under other functional registrations. No changes are required to current documentation and processes if BC Hydro or FortisBC register as a PC.**	**No additional costs**	**No additional costs**	**N/A**	**Recommended effective date immediately after BCUC approval.**
MOD-031-3 R1	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - Remove applicability Load Serving Entity	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**FortisBC currently provides demand and energy data required by this standard to BC Hydro as a Balancing Authority under the annual WECC Loads and Resources Data Request. BC Hydro has indicated there will be no additional data requests required to be completed by FortisBC if BC Hydro registers as the PC for the province.** **If FortisBC registers as a PC, FortisBC does not expect to identify a need for the collection of Total Internal Demand, Net Energy for Load, and Demand Side Management data since FortisBC would not have other TP or DP registered entities in its BES footprint. This means this standard would not be applicable to FortisBC and no changes are required to current documentation and processes.**	**No additional costs** **No additional costs**	**No additional costs** **No additional costs**	**N/A** **N/A**	**Recommended effective date immediately after BCUC approval.** **Recommended effective date immediately after BCUC approval.**
MOD-031-3 R2	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**
MOD-031-3 R3	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**
MOD-031-3 R4	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**	**See MOD-031-3 R1**

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FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Requirements	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
MOD-032-1 R1	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. Added entities responsible for providing the data in R1.3	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	FortisBC currently provides the steady-state, dynamics, and short circuit modeling data required by this standard to BC Hydro. BC Hydro has not indicated if there will be new or modified data requirements and reporting procedures to be completed by FortisBC or other GO registered entities if BC Hydro registers as the PC for the province. If no additional data requests are issued by BC Hydro as the PC there would be no cost increase. FortisBC will need to develop new steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for use in developing models within the FortisBC BES footprint.	$0 - Unknown $5,000 - $10,000	$0 - Unknown No additional costs	FortisBC cannot estimate any costs without knowing any additional BC Hydro data request requirements. N/A	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date is 24-36 months after BCUC approval.
MOD-032-1 R2	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-031-3 R1	See MOD-032-1 R1
MOD-032-1 R3	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1
MOD-032-1 R4	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1	See MOD-032-1 R1
MOD-033-2 R1	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	BC Hydro will need to implement a documented data validation process and complete a comparison of the performance of the PC's portion of the system model to actual system behavior at least once every 24 calendar months through simulation. BC Hydro has not provided a data validation process or requirements information to FortisBC. FortisBC will need to implement a documented data validation process and complete a comparison of the performance of the FortisBC BES footprint system model to actual system behavior at least once every 24 calendar months through simulation.	Unknown $40,000 - $70,000	Unknown $40,000 - $70,000	FortisBC cannot estimate any costs without knowing the BC Hydro data validation process and requirements. Ongoing costs are required every 24 calendar months.	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date is 24-36 months after BCUC approval.
MOD-033-2 R2	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	See MOD-033-2 R1	See MOD-033-2 R1	See MOD-033-2 R1	See MOD-033-2 R1	See MOD-033-2 R1
NUC-001-4 ALL Requirements	RSAW Not on NERC	**Nuclear Plant Interface Coordination** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.	NUC-001-3	N/A	N/A	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	NUC-001-4 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No impact to FortisBC.	No additional costs	No additional costs	N/A	Recommended effective date immediately after BCUC approval.
PRC-006-4 DB1	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	BC Hydro and FortisBC both already participate in UFLS data submittals, reviews, implementations, and assessments required for compliance with this standard and as members of the WECC UFLS Working Group. Note, FortisBC participates through the North West Power Pool (NWPP) with the NWPP participating as a WECC UFLS Working Group member on behalf of FortisBC and other NWPP member entities.	No additional costs	No additional costs	N/A	Recommended effective date immediately after BCUC approval.
PRC-006-4 DB11	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 15	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	See PRC-006-4 DB1	See PRC-006-4 DB1	See PRC-006-4 DB1	See PRC-006-4 DB1	See PRC-006-4 DB1

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.															
FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)															
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 DB12	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 16	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 DB2	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 17	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 DB3	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 18	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 DB4	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 19	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R11	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 20	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB11.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R12	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 21	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB12.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R13	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 22	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB12.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R14	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 23	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R15	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 24	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R1	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 25	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB1.**	**N/A**	**N/A**	**N/A**	**N/A**

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FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 R2	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 26	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB2.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R3	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 27	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - Update reference to PRC-006-4	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB3.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R4	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 28	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - Update reference to PRC-006-4	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB4.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R5	RSAW N/A	**Title: Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 29	PRC-006-3 Adopted 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**Replaced by WECC regional variance requirement DB1.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-006-4 R6	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 30	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R7	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 31	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R8	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 32	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R9	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 33	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-006-4 R10	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 34	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**	**See PRC-006-4 DB1**
PRC-010-2 R1	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**It is currently unknown if BC Hydro would require FortisBC to implement an Under Voltage Load Shedding (UVLS) program or complete UVLS studies for the FortisBC TP area. If FortisBC is not required to implement a UVLS program or complete UVLS studies with BC Hydro as the PC there would be no cost increase.** **FortisBC currently does not have any UVLS programs within the FortisBC BES footprint and does not expect to implement a new UVLS program. This means this standard would be not applicable to FortisBC and no changes are required to current documentation and processes.**	**$0 - Unknown** **No additional costs**	**$0 - Unknown** **No additional costs**	**FortisBC cannot estimate any costs without knowing the BC Hydro UVLS requirements.** **N/A**	**Recommended effective date is 24-36 months after BCUC approval.** **Recommended effective date immediately after BCUC approval.**

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FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
PRC-010-2 R2	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-010-2 R3	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-010-2 R4	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Added subpoints: 4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and 4.2. The performance (i.e., operation and non operation) of the UVLS Program equipment.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-010-2 R5	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Removed deficiencies in its UVLS Program	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-010-2 R6	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-010-2 R7	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-010-2 R8	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**	**See PRC-010-2 R1**
PRC-012-2 R1	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	**Applicable to RAS-entities and RC, not PC.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-012-2 R2	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	**Applicable to RAS-entities and RC, not PC.**	**N/A**	**N/A**	**N/A**	**N/A**
PRC-012-2 R4	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Abeyance Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adpoted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	**BC Hydro would be required to evaluate each RAS within its PC area at least once every 5 calendar years. It is currently unknown if BC Hydro would require additional data to evaluate FortisBC RAS systems or if corrective actions would need to be implemented as identified in the BC Hydro evaluations.** **FortisBC will need to perform an evaluation of each RAS within its BES footprint at least once every 5 calendar years. The majority of this work is completed in each annual planning assessment, so only minor documentation updates are required for compliance with this standard.**	**Unknown** **No additional costs**	**Unknown** **No additional costs**	**FortisBC cannot estimate any costs without knowing the BC Hydro RAS evaluation requirements and results.** **N/A**	**Recommended effective date is 24-36 months after BCUC approval.** **Recommended effective date is 24-36 months after BCUC approval.**

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
PRC-023-4 R3	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	FortisBC does not use criterion 7, 8, 9, 12, or 13 as defined in this standard, therefore, this requirement does not apply to FortisBC.	N/A	N/A	N/A	N/A
PRC-023-4 R4	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	FortisBC does not use criterion 2 as defined in this standard, therefore, this requirement does not apply to FortisBC.	N/A	N/A	N/A	N/A
PRC-023-4 R6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	BC Hydro would need to conduct an assessment at least once each calendar year, with no more than 15 months between assessments, to determine the 100kV-200kV circuits in its PC area which must comply with the PRC-023-4 loadability requirements. It is currently unknown if BC Hydro would require additional studies to evaluate FortisBC 100kV-200kV circuits or if these circuits would need to comply this standard as identified in the BC Hydro assessments. FortisBC would need to conduct an assessment at least once each calendar year, with no more than 15 months between assessments, to determine the 100kV-200kV circuits in its BES footprint which must comply with the PRC-023-4 loadability requirements. FortisBC 100kV-200kV circuits would need to comply with this standard if they meet the required criteria.	Unknown $5,000 - $10,000	Unknown $5,000 - $10,000	FortisBC cannot estimate any costs without knowing the BC Hydro RAS evaluation requirements and results. N/A	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date is 24-36 months after BCUC approval.
PRC-024-3 R3	RSAW N/A	**Title: Frequency and Voltage Protection Settings for Generating Resources** To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).	PRC-024-2 PRC-024-3 is being assessed on Assessment 14	PRC-024-2 Adopted 2016 Assessment Report 9 R-32-16	3 - Each Generator Owner shall document each known regulatory or equipment limitation that prevents an applicable generating resource(s) with frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. 3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following: • Identification of a regulatory or equipment limitation. • Repair of the equipment causing the limitation that removes the limitation. • Replacement of the equipment causing the limitation with equipment that removes the limitation. • Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.	N/A	PA/PC	Docket No. RD20-7-000 Issued July 9, 2020 Publish Date TBA	Comments on the collection of information are due September 29, 2020.	PRC-024-3 Implementation Plan Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. US Enforcement Date of Standard: 01-Oct-2022	These requirements are applicable to GO entities with data submittals required to the TP and PC, therefore, BC Hydro and FortisBC are already required to be compliant with this standard as TPs. Minimal changes are expected to current documentation and processes if BC Hydro or FortisBC register as a PC.	No additional costs	No additional costs	N/A	Recommended effective date immediately after BCUC approval.
PRC-024-3 R4	RSAW N/A	**Title: Frequency and Voltage Protection Settings for Generating Resources** To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).	PRC-024-2 PRC-024-3 is being assessed on Assessment 14	PRC-024-2 Adopted 2016 Assessment Report 9 R-32-16	3 - Each Generator Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required.	N/A	PA/PC	Docket No. RD20-7-000 Issued July 9, 2020 Publish Date TBA	Comments on the collection of information are due September 29, 2020.	PRC-024-3 Implementation Plan Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. US Enforcement Date of Standard: 01-Oct-2022	See PRC-024-3 R3	See PRC-024-3 R3	See PRC-024-3 R3	See PRC-024-3 R3	See PRC-024-3 R3
PRC-026-1 R1	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	BC Hydro would need to identify and communicate any angular stability or power swing issues at least once each calendar year, to each GO and TO entity in its PC area. Then, applicable GO and TO entities must comply with the relay loadability requirements specified in this standard. It is currently unknown if BC Hydro studies identify any FortisBC elements that would need to comply with this standard. FortisBC would need to complete an angular stability and power swing study document at least once each calendar year. FortisBC does not have any separate registered GO and TO entities in its BES footprint. FortisBC does not expect to have any elements that would need to comply this standard.	Unknown $10,000 - $20,000	Unknown $10,000 - $20,000	FortisBC cannot estimate any costs without knowing the BC Hydro angular stability and power swing study results. N/A	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date is 24-36 months after BCUC approval.
PRC-027-1 R1	RSAW Not on NERC	**Coordination of Protection Systems for Performance During Faults** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PRC-027-1 Future Effective Assessment Report 12 R-21-19	PRC-001-1.1(ii) Adopted 2016 Assessment Report 9 R-38-15	1. Merging of all R1.3.3 sub clauses	PRC-027-1 Mapping Document	PA/PC	Docket No. RM16-22-000 Issued Jun 7, 2018	13-Aug-2018	PRC-027-1 Implementation Plan Implementation Time: PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved US Enforcement Date 01-Apr-2021	Applicable to TO, GO, and DP, not PC. The supplemental material states that fault current baseline values can be obtained from the short-circuit studies performed by the TP, PC, or TO but there are no standard requirements that require this data to be provided. FortisBC does not currently have any separate registered TO, GO, or DP entities in its BES footprint.	N/A	N/A	N/A	N/A
PRC-027-1 R2	RSAW Not on NERC	**Coordination of Protection Systems for Performance During Faults** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PRC-027-1 Future Effective Assessment Report 12 R-21-19	PRC-001-1.1(ii) Adopted 2016 Assessment Report 9 R-38-15	1. Added BES to Option 2	PRC-027-1 Mapping Document	PA/PC	Docket No. RM16-22-000 Issued Jun 7, 2018	13-Aug-2018	PRC-027-1 Implementation Plan Implementation Time: PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved US Enforcement Date 01-Apr-2021	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1

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FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
TPL-001-5.1 R1	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Updated requirement body to reference MOD-032 Part 1.1.2 and subparts have been deleted	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**
TPL-001-5.1 R2	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 15	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 2.1.4 moved to Part 2.1.3. A properly planned Transmission system should facilitate maintenance outages without Non Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL 001 5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4. Part 2.1.5 Document internal conforming as reflecting in R2, Part 2.4.5 Part 2.4.3 has been moved back to 2.4.3 as it was in TPL 001 4. Part 2.4.4 TPL 001 4, Part 2.4.3 moved to TPL 001 5, Part 2.4.4.Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4. Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy. Part 2.7 Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard. Part 2.7 Updated to reflect NERC Glossary Term	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**
TPL-001-5.1 R3	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 16	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 3.2 Document internal conforming clean up to move the last sentence of Requirement R3, Part 3.5 to Requirement R3, Part 3.2.	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**
TPL-001-5.1 R4	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 17	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 4.1.1 Updated to reflect NERC Glossary Term Part 4.2 Prior to this change, TPL 001 4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL 001 4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**
TPL-001-5.1 R5	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 18	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**
TPL-001-5.1 R6	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 19	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**	**See TPL-001-5.1 R7**

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
TPL-001-5.1 R7	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 20	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000; Issued June 10, 2020; Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	This requirement states that each PC, in conjunction with each of its TPs, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessments identified in this standard. BC Hydro and FortisBC have not yet determined the scope and responsibilities for each entity's annual Planning Assessments. All requirements are applicable to both TP and PC, therefore, FortisBC is already required to be compliant with this standard as a TP. Minimal changes are required to current documentation and processes.	Unknown No additional costs	Unknown No additional costs	FortisBC cannot estimate any costs without knowing the scope and responsibility for the BC Hydro and FortisBC annual Planning Assessments. N/A	Recommended effective date is 24-36 months after BCUC approval. Recommended effective date immediately after BCUC approval.
TPL-001-5.1 R8	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 21	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC	Docket No. RD20-8-000; Issued June 10, 2020; Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	See TPL-001-5.1 R7	See TPL-001-5.1 R7	See TPL-001-5.1 R7	See TPL-001-5.1 R7	See TPL-001-5.1 R7
TPL-007-4 D.A 11.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11
TPL-007-4 D.A 11.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11
TPL-007-4 D.A 11.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11	See TPL-007-4 R11
TPL-007-4 D.A 7.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - requirement D.A 7.3 - Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R7	See TPL-007-4 R7	See TPL-007-4 R7	See TPL-007-4 R11	See TPL-007-4 R7
TPL-007-4 D.A 7.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R7	See TPL-007-4 R7	See TPL-007-4 R7	See TPL-007-4 R11	See TPL-007-4 R7
TPL-007-4 D.A 7.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R7	See TPL-007-4 R7	See TPL-007-4 R7	See TPL-007-4 R11	See TPL-007-4 R7
TPL-007-4 R1	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	This requirement states that each PC, in conjunction with each of its TPs, shall identify the individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing processes to obtain GMD measurement data as specified in this standard. BC Hydro and FortisBC have not yet determined the scope and responsibilities for each entity's GMD Vulnerability Assessments. See TPL-007-4 R2-R13	Unknown See TPL-007-4 R2-R13	Unknown See TPL-007-4 R2-R13	FortisBC cannot estimate any costs without knowing the scope and responsibility for the BC Hydro and FortisBC GMD Vulnerability Assessments. See TPL-007-4 R2-R13	Recommended effective date is 24-36 months after BCUC approval. See TPL-007-4 R2-R13
TPL-007-4 R2	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R1 The WECC Data Subcommittee, Studies Subcommittee, and the System Data Working Group have accepted the responsibility to maintain models, perform the study or studies needed to complete benchmark and supplemental Geomagnetic Disturbance (GMD) Vulnerability Assessments, and implement process(es) to obtain GMD measurement data as specified in this standard. WECC currently provides this service free-of-charge to member entities. Minimal effort will be required for FortisBC to review and respond to WECC data requests and studies.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.

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FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 R3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	See TPL-007-4 R1 FortisBC currently has acceptable steady state voltage performance criteria for the FortisBC BES footprint that could be applied to GMD Vulnerability Assessments with minimal new effort.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	See TPL-007-4 R1 The WECC Studies Subcommittee has completed benchmark GMD Vulnerability Assessments of the Near-Term Transmission Planning Horizon for on-peak and off-peak loads that include the FortisBC BES footprint for the 2019 study year. FortisBC will need to confirm the WECC GMD Vulnerability Assessments study results on an ongoing basis.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 $20,000 - $40,000	See TPL-007-4 R1 Ongoing costs are required every 60 calendar months.	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R1 The WECC Studies Subcommittee has provided GIC flow information to be used for the benchmark thermal impact assessment of transformers for all applicable Bulk Electric System (BES) power transformers in the FortisBC BES footprint. This GIC flow information includes the maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event. FortisBC does not have any separate registered GO and TO entities in its BES footprint that the GIC flow information needs to be provided to under this requirement.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R6	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	See TPL-007-4 R1 The benchmark maximum effective GIC values provided by the WECC Studies Committee for all applicable Bulk Electric System (BES) power transformers in the FortisBC BES footprint is less than 75 amps per phase. Therefore, this requirement is not applicable to FortisBC. (This analysis and the estimated costs for this requirement are contingent that the benchmark maximum effective GIC values for all BES transformers in the FortisBC BES footprint will continue to be less than 75 amps per phase going forward.)	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R7	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Change to Part 7.3 Include a timetable, subject to approval for any extension sought under Part 7.4 for implementing the selected actions from part 7.1. Part 7.4 Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following : Part 7.4.1 Circumtances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how thoes circumtances are beyond the control of the responsible entity. Part 7.4.2 Remove requirement 7.4.2 in its entirety. Part 7.4.3 Added requirement 7.4.3 Part 7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	See TPL-007-4 R1 The WECC Studies Subcommittee has completed benchmark GMD Vulnerability Assessments for the entire WECC area for the 2019 study year and no steady state planning benchmark GMD event performance issues have been identified for the FortisBC BES footprint. Therefore, this requirement is not applicable to FortisBC. (This analysis and the estimated costs for this requirement are contingent that no steady state planning benchmark GMD performance issues are identified for the FortisBC BES footprint going forward.)	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R8	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Delete requirement 8.3	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	See TPL-007-4 R1 The WECC Studies Subcommittee has completed the supplemental GMD Vulnerability Assessments of the Near-Term Transmission Planning Horizon for on-peak and off-peak loads that include the FortisBC BES footprint for the 2019 study year. FortisBC will need to confirm the WECC GMD Vulnerability Assessments study results on an ongoing basis.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 See TPL-007-4 R4	See TPL-007-4 R1 See TPL-007-4 R4	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R9	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	See TPL-007-4 R1 The WECC Studies Subcommittee has provided GIC flow information to be used for the supplemental thermal impact assessment of transformers for all applicable BES transformers in the FortisBC BES footprint. This GIC flow information includes the maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event. FortisBC does not have any separate registered GO and TO entities in its BES footprint that the GIC flow information needs to be provided to under this requirement.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R10	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	See TPL-007-4 R1 The supplemental maximum effective GIC values provided by the WECC Studies Committee for all applicable BES power transformers in the FortisBC BES footprint is less than 85 amps per phase. Therefore, this requirement is not applicable to FortisBC. (This analysis and the estimated costs for this requirement are contingent that the supplemental maximum effective GIC values for all BES transformers in the FortisBC BES footprint will continue to be less than 85 amps per phase going forward.)	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R11	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New Requirement	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	See TPL-007-4 R1 The WECC Studies Subcommittee has completed supplemental GMD Vulnerability Assessments for the entire WECC area for the 2019 study year and no steady state planning supplemental GMD event performance issues have been identified for the FortisBC BES footprint. Therefore, this requirement is not applicable to FortisBC. (This analysis and the estimated costs for this requirement are contingent that no steady state planning supplemental GMD performance issues are identified for the FortisBC BES footprint going forward.)	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell) Analysis with BC Hydro registered as the PC for the entire province is shown in green. Analysis with FortisBC registering as the PC for the FortisBC Bulk Electric System (BES) footprint is shown in red. Analysis that is not dependent on BC Hydro or FortisBC PC registration is shown in black.	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 R12	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	See TPL-007-4 R1 FortisBC currently has Intelligent Electronic Devices (IEDs) installed within the FortisBC system that are capable of monitoring GIC data and minimal new effort would be required to implement a process to collect this data.	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.
TPL-007-4 R13	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	See TPL-007-4 R1 Natural Resources Canada currently has a magnetic observatory located in Victoria, BC. Geomagnetic field data from this observatory is available free of charge for non-commercial use from the Natural Resources Canada website. Therefore, minimal new effort would be required to implement a process to collect this data. (This analysis and the estimated costs are contingent that geomagnetic field data will continue to be made available free of charge going forward.)	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 No additional costs	See TPL-007-4 R1 N/A	See TPL-007-4 R1 Recommended effective date is 24-36 months after BCUC approval.

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FortisBC Inc. (DP, GO, GOP, RP, TO, TOP, TP, TSP)

Assessment Number	FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 8, 2020 Glossary of Terms	Acronym (If Applicable)	FERC Approved New/Revised/Retired NERC Term Definitions against Terms and Definitions listed in Columns "D" and "E" (changes to definition indicated by red text; deletions are not indicated)	Current BCUC Adopted Terms from October 8, 2020 Glossary of Terms	Current BCUC Adopted Definition from October 8, 2020 Glossary of Terms	FERC Approval Date of New/Revised/Retired NERC Term and Definition	Effective Date of New/Revised/Retired NERC Term and Definition in United States	Stakeholder Comments (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental Cost Associated with Revised/New Term and Definition, if any ($). (Press Alt-Enter to insert a carriage return in a cell)		BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time ($)	Cost Ongoing ($)	
11	**Remedial Action Scheme** *Glossary term is specific to the currently adopted CIP-002-3/5.1, CIP-003-5, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, EOP-004-3, FAC-010-3, FAC-011-3, MOD-029-2a, MOD-030-3, NUC-001-3, PRC-001-1.1(ii), PRC-004-5(i), PRC-004-WECC-2, PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-4, PRC-024-2, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a standards	RAS	N/A	Retired	See "Special Protection System"	31-Mar-2017	31-Mar-2017	No impact to FortisBC.	No additional costs	No additional costs	Recommended retirement date immediately after BCUC approval.
11	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the currently adopted CIP-002-3/5.1, CIP-003-5, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, CIP-011-2, EOP-004-3, FAC-010-3, FAC-011-3, IRO-002-4, IRO-005-3.1a, IRO-008-2, IRO-010-2, MOD-029-2a, MOD-030-3, PRC-001-1.1(ii), PRC-004-5(i), PRC-005-2(i), PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-2, PRC-023-4, PRC-024-2, PRC-025-1, TOP-001-3, TOP-002-4, TOP-003-3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a standards	SPS	N/A	Retired	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	31-Mar-2017	31-Mar-2017	No impact to FortisBC.	No additional costs	No additional costs	Recommended retirement date immediately after BCUC approval.
10	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the PRC-010-2 standard which is held in abeyance in B.C., and is indirectly referenced from the PRC-006-2 (also held in abeyance in B.C.) via the term Special Protection System - SPS, as well as the currently adopted CIP-002-3/5.1, EOP-004-2, FAC-010-2.1, FAC-011-2, IRO-005-3.1a, MOD-029-1a, MOD-030-2, NUC-001-2/3, PRC-001-1.1, PRC-004-WECC-1, PRC-005-2(i), PRC-015-0, PRC-016-0.1, PRC-017-0, PRC-021-1, PRC-023-1/2/3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a	SPS	See "Remedial Action Scheme"	Special Protection System (Remedial Action Scheme)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	23-Jun-16	01-Apr-17	No impact to FortisBC.	No additional costs	No additional costs	Recommended effective date immediately after BCUC approval.
9	**Remedial Action Scheme** *Glossary term is specific to the new PRC-010-2 standard, and is indirectly referenced from the new PRC-006-2 and PRC-005-2(i) standards (via the term Special Protection System - SPS) as well as the currently adopted CIP-002-3/5.1, EOP-004-2, FAC-010-2.1, FAC-011-2, IRO-005-3.1a, MOD-029-1a, MOD-030-2, NUC-001-2/3, PRC-001-1.1, PRC-004-WECC-1, PRC-015-0, PRC-016-0.1, PRC-017-0, PRC-021-1, PRC-023-1/2/3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a	RAS	Please refer to the NERC Glossary of Terms for the definition as it is too long to replicate here.	Remedial Action Scheme	"See Special Protection System" which is defined as: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	19-Nov-15	01-Apr-17	No impact to FortisBC.	No additional costs	No additional costs	Recommended effective date immediately after BCUC approval.
9	**Under Voltage Load Shedding Program** *Glossary term is specific to the new PRC-010-2 standard	UVLS Program	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate under voltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled under voltage-based load shedding is not included.	New	N/A	19-Nov-15	01-Apr-17	No impact to FortisBC.	No additional costs	No additional costs	Recommended effective date immediately after BCUC approval.

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
CIP-002-5.1a R1	CIP-002-5.1a RSAW	**Cyber Security — BES Cyber System Categorization** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.	CIP-002-5.1a Adopted 2018 Assessment Report 11 R-33-18	CIP-002-5.1 Adopted 2015 Assessment Report 8 R-38-15	No Redline	N/A	BA, DP, GO, GOP, IA, IC, RC, TO, TOP	Docket No. RD17-2-000 Issued December 27, 2016	27-Dec-2016	CIP-002-5.1a Implementation Plan Implementation Time: 24 Months Minimum US Enforcement Date 21-Dec-2016	No significant changes to GO-relevant requirements.	0	0		Immediately after adoption by the BCUC.
CIP-014-2 R2	CIP-014-2 RSAW	**Physical Security** To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.	CIP-014-2 Adopted 2016 Assessment Report 9 R-32-16A	None - CIP-014-2 was new standard	New Standard N/A	CIP-014-2 Mapping Document	TO	Docket No. RD15-4-000 Issued July 14, 2015	2-Oct-2015	CIP-014-2 Implementation Plan Implementation Time: CIP-014-2 shall become effective on the later of the first day following the Effective Date of CIP-014-1 or the first day after CIP-014-2 is approved. US Enforcement Date 10-Feb-2015	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
EOP-003-2 R2	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Plans needed for automatic load shedding for underfrequency or undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2 Mapping Document	TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
EOP-003-2 R4	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
EOP-003-2 R7	EOP-003-2 RSAW	**Load Shedding Plans** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.	EOP-003-1 EOP-003-2 is in Abeyance	EOP-003-1 Adopted 2008 Assessment Report 1 G-67-09	2. Removal of Balancing Authority	EOP-003-2 Mapping Document	TOP	Docket No. RM11-20-000 Issued May 7, 2012	7-May-2012	EOP-003-2 Implementation Plan Implementation Time: Effective one year following the first day of the first calendar quarter after applicable regulatory approvals. US Enforcement Date 01-Oct-2013	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-002-3 R1	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-002-3 R2	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	GO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No significant changes to GO-relevant requirements.	0	0		Immediately after adoption by the BCUC.
FAC-002-3 R3	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. Remove Applicability Load Serving Entity	N/A	DP, TO, PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-20	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-002-3 R4	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	TO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-002-3 R5	RSAW N/A	**Facility Interconnection Studies** To study the impact of interconnecting new or materially modified Facilities on the Bulk Electric System.	FAC-002-2 FAC-002-3 is being assessed in Assessment 14	FAC-002-2 Adopted 2015 Assessment Report 8 R-38-15	3. No changes to the requirement from previous version.	N/A	GO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	FAC-002-3 Implementation Plan Implementation Time: Effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	No significant changes to GO-relevant requirements.	0	0		Immediately after adoption by the BCUC.
FAC-008-3 R7	FAC-008-3 RSAW	**Facility Ratings** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.	FAC-008-3 Adopted 2014 Assessment Report 7 R-32-14	FAC-008-1 and FAC-009-1 No Assessment Report	3. Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities.	N/A	GO	Docket No. RD11-10-000 Issued Nov 17, 2011	17-Nov-2011	FAC-008-3 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved. US Enforcement Date 01-Jan-2013	BC Hydro is already provided with this information. Cost or implementation timing would be dependent on if BC Hydro as PC would require any other documentation	0	0		Immediately after adoption by the BCUC. Dependent on whether BC Hydro as PC will require any other documentation.
FAC-008-3 R8	FAC-008-3 RSAW	**Facility Ratings** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.	FAC-008-3 Adopted 2014 Assessment Report 7 R-32-14	FAC-008-1 and FAC-009-1 No Assessment Report	3. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), 12 Such as temporary de-ratings of impaired equipment in accordance with good utility practice. Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s)	N/A	GO, TO	Docket No. RD11-10-000 Issued Nov 17, 2011	17-Nov-2011	FAC-008-3 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved. US Enforcement Date 01-Jan-2013	BC Hydro is already provided with this information. Cost or implementation timing would be dependent on if BC Hydro as PC would require any other documentation	0	0		Immediately after adoption by the BCUC. Dependent on whether BC Hydro as PC will require any other documentation.
FAC-010-3 R1	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Implementation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-010-3 R2	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Implementation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
FAC-010-3 R3	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. Removal of special protection systems in R3.4	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Implementation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-010-3 R4	FAC-010-3 RSAW	**System Operating Limits Methodology for the Planning Horizon** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-10-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-010-2.1 Adopted 2011 Assessment Report 3 G-162-11	3. No changes to the requirement from previous version.	FAC-010-3 Mapping Document	PA/PC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-010-3 Implementation Plan Implementation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-011-3 R3	FAC-011-3 RSAW	**System Operating Limits Methodology for the Operations Horizon** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-11-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-011-2 Adopted 2010 Assessment Report 2 G-167-10	3. Updated with definition and implementation of Remedial Action Scheme		RC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-011-3 Implementation Plan Implementation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-011-3 R4	FAC-011-3 RSAW	**System Operating Limits Methodology for the Operations Horizon** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-11-3 Adopted 2017 Assessment Report 10 R-39-17	FAC-011-2 Adopted 2010 Assessment Report 2 G-167-10	3. No changes to the requirement from previous version.		RC	Docket Nos. RM15-7-000 & RM15-12-000 & RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	FAC-011-3 Implementation Plan Implementation Time: effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-014-2 R3	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-014-2 R4	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	TP	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-014-2 R5	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	RC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
FAC-014-2 R6	FAC-014-2 RSAW	**Establish and Communicate System Operating Limits** To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.	FAC-014-2 Adopted 2010 Assessment Report 2 G-167-10	FAC-014-1 Adopted 2008 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM08-11-000 Issued Mar 20, 2009	29-Apr-2009	FAC-014-2 Implementation Plan Implementation Time: Not specified US Enforcement Date 29-Apr-2009	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
IRO-017-1 R3	IRO-017-1 RSAW	**Outage Coordination** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	IRO-017-1 Adopted 2017 Assessment Report 10 R-39-17	None - IRO-017-1 was new standard	New Standard N/A	New Standard N/A	PA/PC, TP	Docket No. RM15-16-000 Issued Nov 19, 2015	26-Jan-2016	IRO-017-1 Implementation Plan Implementation Time: Twelve month implementation period US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
IRO-017-1 R4	IRO-017-1 RSAW	**Outage Coordination** To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	IRO-017-1 Adopted 2017 Assessment Report 10 R-39-17	None - IRO-017-1 was new standard	New Standard N/A	New Standard N/A	PA/PC, TP	Docket No. RM15-16-000 Issued Nov 19, 2015	26-Jan-2016	IRO-017-1 Implementation Plan Implementation Time: Twelve month implementation period US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-001-1a R4	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	TSP	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-001-1a R5	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	TSP	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-001-1a R9	MOD-001-1a RSAW	**Available Transmission System Capability** To ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors	MOD-001-1a	MOD-001-1a Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	TSP	Docket No. RD10-5-000 Issued Sept 16, 2010	16-Sep-2010	MOD-001-1a Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date all four standards (MOD-001-1, MOD-028-1, MOD-029-1, and MOD-030-1) are approved. US Enforcement Date 01-Apr-2011	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-004-1 R2	MOD-004-1 RSAW	**Capacity Benefit Margin** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	MOD-004-1	MOD-004-1 Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	TSP	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-004-1 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-004-1 R9	MOD-004-1 RSAW	**Capacity Benefit Margin** To promote the consistent and reliable calculation, verification, preservation, and use of Capacity Benefit Margin (CBM) to support analysis and system operations.	MOD-004-1	MOD-004-1 Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	TP, TSP	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-004-1 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-008-1 R3	MOD-008-1 RSAW	**Transmission Reliability Margin Calculation Methodology** To promote the consistent and reliable calculation, verification, preservation, and use of Transmission Reliability Margin (TRM) to support analysis and system operations.	MOD-008-1	MOD-008-1 Adopted 2011 Assessment Report 4 G-175-11	No Redline	N/A	TOP	Docket No. RM08-09-000 Issued Nov 24, 2009	8-Feb-2010	MOD-008-1 Implementation Plan Implementation Time: All requirements in the standard should become effective on the first day of the first calendar quarter that is twelve months beyond the date the standard is approved US Enforcement Date 01-Apr-2011	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

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Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
MOD-031-3 R1	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - Remove applicability Load Serving Entity	N/A	PA/PC, BA	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-031-3 R2	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	BA, DP, TP	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-031-3 R3	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	PA/PC, BA	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-031-3 R4	RSAW Not on NERC	**Demand and Energy Data** To provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data.	MOD-031-2 MOD-031-3 is being assessed in Assessment 14	MOD-031-2 Adopted 2017 Assessment Report 10 R-39-17	3 - No changes to the requirement from previous version	N/A	BA, DP, TP	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-031-3 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-032-1 R1	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. Added entities responsible for providing the data in R1.3	MOD-032-1 Mapping Document	PA/PC, TP	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-032-1 R2	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	BA, GO, LSE, RP,	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	Entities will need to develop SC models.	20,000	30,000	All costs here are per registered entity, *5 for total impact. Ongoing costs include the 5-year interval for updating the model	Will require at least 12 months, but prefer the first day of the first calendar quarter that is 24 months after the date that the standard is approved.
MOD-032-1 R3	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	BA, GO, LSE, RP,	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	Once entities have developed the SC models, as per R2, they will be able to be compliant with R3.	0	0		Will require at least 12 months, but prefer the first day of the first calendar quarter that is 24 months after the date that the standard is approved.
MOD-032-1 R4	MOD-032-1 RSAW	**Data for Power System Modeling and Analysis** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.	MOD-032-1 in Abeyance	MOD-032-1 Abeyance 2015 Assessment Report 8 R-38-15	1. No change to the requirement from previous version	MOD-032-1 Mapping Document	PA/PC	Docket No. RD14-5-000 Issued May 1, 2014	1-May-2014	MOD-032-1 Implementation Plan Implementation Time: R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved. R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved. US Enforcement Date 01-Jul-2015	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-033-2 R1	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
MOD-033-2 R2	RSAW Not on NERC	**Steady-State and Dynamic System Model Validation** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.	MOD-033-1 in Abeyance MOD-033-2 is being assessed in Assessment 14	MOD-033-1 Abeyance 2015 Assessment Report 8 R-38-15	2 - No changes to the requirement from previous version	N/A	RC, TOP	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	MOD-033-2 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
NUC-001-4 ALL Requirements	RSAW Not on NERC	**Nuclear Plant Interface Coordination** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.	NUC-001-3	N/A	N/A	N/A	TO, TOP, TP, TSP, BA, RC, DP, GO, GOP, PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	NUC-001-4 Implementation Plan Implementation Time: standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date 01-Apr-2021	Not applicable as entities are not nuclear power.	0	0		n/a
PRC-006-4 DB1	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 DB11	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 DB12	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 DB2	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-006-4 DB3	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 DB4	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R14	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R15	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R6	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R7	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R8	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC, DP, TO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R9	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC, DP, TO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-006-4 R10	RSAW N/A	**Automatic Underfrequency Load Shedding** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.	PRC-006-3 in Abeyance PRC-006-4 is being assessed in Assessment 14	PRC-006-3 Abeyance 2018 Assessment Report 11 R-33-18	4 - No changes to the requirement from previous version	N/A	PA/PC, TO	Docket No. RD20-4-000 Issued Oct 30, 2020	30-Oct-2020	PRC-006-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Apr-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R1	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R2	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	DP, TO	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R3	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R4	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Added subpoints: 4.1. Whether its UVLS Program resolved the undervoltage issues associated with the event, and 4.2. The performance (i.e., operation and non operation) of the UVLS Program equipment.	PRC-010-2 Mapping Document	PA/PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R5	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. Removed deficiencies in its UVLS Program	PRC-010-2 Mapping Document	PA/PC, TP	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

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Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superseded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
PRC-010-2 R6	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R7	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	DP, TO	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-010-2 R8	PRC-010-2 RSAW	**Undervoltage Load Shedding** To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs).	PRC-010-0 PRC-010-2 Abeyance	PRC-010-0 Adopted 2009 Assessment Report 1 G-67-09	2. No changes to the requirement from previous version.	PRC-010-2 Mapping Document	PA/PC	Docket No. RD15-5-000 Issued Nov 19, 2015	19-Nov-2015	PRC-010-2 Implementation Plan Implementation Time: PRC 010 2 shall become effective on the later of the first day following the Effective Date of PRC 010 1 or the first day of the first calendar quarter after the standard is approved by an applicable governmental authority. US Enforcement Date 02-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-012-2 R1	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adopted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	DP, GO, TO	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	Not applicable as the entities do not have Remedial Action Schemes (RAS).	0	0		n/a
PRC-012-2 R2	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Future Effective Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adopted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	RC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-012-2 R4	PRC-012-2 RSAW	**Remedial Action Schemes** To ensure that Remedial Action Schemes (RAS) do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System (BES).	PRC-012-2 Abeyance Assessment Report 11 R-33-18	PRC-015-1/PRC-016-1 Adopted 2017 Assessment Report 10 R-39-17	2. No changes to the requirement from previous version.	PRC-012-2 Mapping Document	PA/PC	Docket No. RM16-20-000 Issued Sept 20, 2017	27-Nov-2017	PRC-012-2 Implementation Plan Implementation Time: PRC-012-2 shall become effective on the first day of the first calendar quarter that is thirty six (36) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2021	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-023-4 R3	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable to the entities.	0	0		n/a
PRC-023-4 R4	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	DP, GO, TO	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable to the entities.	0	0		n/a
PRC-023-4 R6	PRC-023-4 RSAW	**Transmission Relay Loadability** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.	PRC-023-4 Adopted 2017 Assessment Report 10 R-39-17	PRC-023-3 Adopted 2015 Assessment Report 8 R-38-15	4. No changes to the requirement from previous version.	N/A	PA/PC	Docket No. RM15-7-000, RM15-12-000, and RM15-13-000 Issued Nov 19, 2015	25-Jan-2016	PRC-023-4 Implementation Plan Implementation Time: Revised Reliability Standards and the revised definition of "Remedial Action Scheme" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are approved. US Enforcement Date 01-Apr-2017	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-024-3 R3	RSAW N/A	**Title: Frequency and Voltage Protection Settings for Generating Resources** To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).	PRC-024-2 PRC-024-3 is being assessed on Assessment 14	PRC-024-2 Adopted 2016 Assessment Report 9 R-32-16	3 - Each Generator Owner shall document each known regulatory or equipment limitation that prevents an applicable generating resource(s) with frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. 3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following: • Identification of a regulatory or equipment limitation. • Repair of the equipment causing the limitation that removes the limitation. • Replacement of the equipment causing the limitation with equipment that removes the limitation. • Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.	N/A	GO, PC	Docket No. RD20-7-000 Issued July 9, 2020 Publish Date TBA	Comments on the collection of information are due September 29, 2020.	PRC-024-3 Implementation Plan Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. US Enforcement Date of Standard: 01-Oct-2022	Comments made on BCUC Assessment Report 14 Feedback Form	0	0		see BCUC Assessment Report 14 Feedback form
PRC-024-3 R4	RSAW N/A	**Title: Frequency and Voltage Protection Settings for Generating Resources** To set protection such that generating resource(s) remain connected during defined frequency and voltage excursions in support of the Bulk Electric System (BES).	PRC-024-2 PRC-024-3 is being assessed on Assessment 14	PRC-024-2 Adopted 2016 Assessment Report 9 R-32-16	3 - Each Generator Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required.	N/A	GO, PC	Docket No. RD20-7-000 Issued July 9, 2020 Publish Date TBA	Comments on the collection of information are due September 29, 2020.	PRC-024-3 Implementation Plan Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. US Enforcement Date of Standard: 01-Oct-2022	Comments made on BCUC Assessment Report 14 Feedback Form	0	0		see BCUC Assessment Report 14 Feedback form
PRC-026-1 R1	PRC-026-1 RSAW	**Relay Performance During Stable Power Swings** To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.	PRC-026-1 Abeyance 2017 Assessment Report 10 R-39-17	None - PRC-026-1 was new standard	New Standard N/A	New Standard N/A	PA/PC	Docket No. RM15-8-000 Issued Mar 17, 2016	23-May-2016	PRC-026-1 Implementation Plan Implementation Time: R1 first day of the first full calendar year that is 12 months after the date that the standard is approved. R2, R3, R4 First day of the first full calendar year that is 36 months after the date that the standard is approved. US Enforcement Date 01-Jan-2018	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
PRC-027-1 R1	RSAW Not on NERC	**Coordination of Protection Systems for Performance During Faults** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PRC-027-1 Future Effective Assessment Report 12 R-21-19	PRC-001-1.1(ii) Adopted 2016 Assessment Report 9 R-38-15	1. Merging of all R1.3.3 sub clauses	PRC-027-1 Mapping Document	DP, GO, TO	Docket No. RM16-22-000 Issued Jun 7, 2018	13-Aug-2018	PRC-027-1 Implementation Plan Implementation Time: PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved US Enforcement Date 01-Apr-2021	Entities to develop a process for developing new and revised Protection System settings. Will need to review data and settings.	30,000	30,000	All costs here are per registered facility, *5 for total cost. Ongoing costs include the 6-year interval for updating the study.	Will require at least 12 months, but prefer the first day of the first calendar quarter that is 24 months after the date that the standard is approved.
PRC-027-1 R2	RSAW Not on NERC	**Coordination of Protection Systems for Performance During Faults** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PRC-027-1 Future Effective Assessment Report 12 R-21-19	PRC-001-1.1(ii) Adopted 2016 Assessment Report 9 R-38-15	1. Added BES to Option 2	PRC-027-1 Mapping Document	DP, GO, TO	Docket No. RM16-22-000 Issued Jun 7, 2018	13-Aug-2018	PRC-027-1 Implementation Plan Implementation Time: PRC-027-1 shall become effective on the first day of the first calendar quarter that is twenty-four (24) months after the date that the standard is approved US Enforcement Date 01-Apr-2021	Entities will need to complete studies, update and implement settings. Entities will need to determine which option to use for R2.	30,000	30,000	All costs here are per registered facility, *5 for total cost. Ongoing costs include the 6-year interval for updating the study.	Will require at least 12 months, but prefer the first day of the first calendar quarter that is 24 months after the date that the standard is approved.

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.														
Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)														
FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-001-5.1 R1	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Updated requirement body to reference MOD-032 Part 1.1.2 and subparts have been deleted	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R2	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 2.1.4 moved to Part 2.1.3. A properly planned Transmission system should facilitate maintenance outages without Non Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL 001 5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4. Part 2.1.5 Document internal conforming as reflecting in R2, Part 2.4.5 Part 2.4.3 has been moved back to 2.4.3 as it was in TPL 001 4. Part 2.4.4 TPL 001 4, Part 2.4.3 moved to TPL 001 5, Part 2.4.4.Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4. Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy. Part 2.7 Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard. Part 2.7 Updated to reflect NERC Glossary Term	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R3	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 3.2 Document internal conforming clean up to move the last sentence of Requirement R3, Part 3.5 to Requirement R3, Part 3.2.	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R4	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - Part 4.1.1 Updated to reflect NERC Glossary Term Part 4.2 Prior to this change, TPL 001 4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL 001 4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R5	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R6	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R7	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-001-5.1 R8	RSAW N/A	**Title: Transmission System Planning Performance Requirements** 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.	TPL-001-4 TPL-001-5.1 is being assessed on Assessment 14	TPL-001-4 Adopted 2015 Assessment Report 8 R-38-15	5.1 - No changes to the requirement from the previous version	TPL-001-5 Mapping Document	PA/PC, TP	Docket No. RD20-8-000 Issued June 10, 2020 Published TBA	10-Jun-2020	TPL-001-5 Implementation Plan (NOTE: NOT TPL-001-5.1) Implementation Time: Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard US Enforcement Date of Standard: 01-Jul-2023	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 D.A 11.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 D.A 11.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 D.A 11.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 D.A 7.3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - requirement D.A 7.3 - Include a timetable, subject to revision by the responsible entity in Part D.A.7.4, for implementing the selected actions from Part 7.1.	N/A	PA/PC	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

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Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 D.A 7.4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 D.A 7.5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New regional variances	N/A	BA, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R1	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R2	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R3	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R4	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R5	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R6	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	GO, TO	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	Entities need to develop GIC models.	30,000	30,000	All costs here are per registered facility, *5 for total cost. Ongoing costs include the 5-year interval for updating the assessment.	Will require at least 12 months to complete over all applicable entities
TPL-007-4 R7	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Change to Part 7.3 Include a timetable, subject to approval for any extension sought under Part 7.4 for implementing the selected actions from part 7.1. Part 7.4 Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following : Part 7.4.1 Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity. Part 7.4.2 Remove requirement 7.4.2 in its entirety. Part 7.4.3 Added requirement 7.4.3 Part 7.5.1 If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R8	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - Delete requirement 8.3	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2023 (phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R9	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Oct-2020	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R10	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	GO, TO	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2022 (Phased in implementation)	Entities need to develop GIC models.	30,000	30,000	All costs here are per registered facility, *5 for total cost. Ongoing costs include the 5-year interval for updating the assessment.	Will require at least 12 months to complete over all applicable entities
TPL-007-4 R11	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - New Requirement	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jan-2024 (phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

Disclaimer: This information has been prepared as input into BC Hydro's Planning Coordinator assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.															
Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)															
FERC Approved New/Revised/Retired Standard/Requirement	RSAW Link	Standard Name and Description	Current BCUC Standard	Current BCUC Superseded or to be Superceded	FERC Approved Revision	FERC Approved Revision Mapping Document	Functional Applicability of FERC Approved Standards/Require	FERC Order No., Order Date and Order Publication Date	Effective Date of FERC Rule Approving the Standard	FERC Approved Standard/Requirement Implementation Time Provided and US Enforcement Date	Stakeholder Comments Organizational Activities and Reliability/Suitability Impact	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any ($)			BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
(Hyperlinks to the Standard)	(Hyperlinks to the available RSAWs)					(Hyperlinks to the mapping documents if available)		(Hyperlinks to the referenced FERC Orders)	(Hyperlinks to the FERC Approval Ruling)	(Hyperlinks to the respective implementation plan and effective dates if applicable)	(Press Alt-Enter to insert a carriage return in a cell)	One Time ($)	Ongoing ($)	Cost Comments	
TPL-007-4 R12	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a
TPL-007-4 R13	TPL-007-4 RSAW	**Transmission System Planned Performance for Geomagnetic Disturbance** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.	TPL-007-3 in Abeyance TPL-007-4 is being assessed in Assessment 14	TPL-007-3 Abeyance 2020 Assessment Report 13 R-19-20	4 - No changes to the requirement from previous version.	N/A	PA/PC, TP	Docket No. RD20-3-000; Issued March 19, 2020; Published April 16, 2020	19-Mar-2020	TPL-007-4 Implementation Plan Implementation Time: Standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the applicable governmental authority's order approving the standard. US Enforcement Date 01-Jul-2021 (Phased in implementation)	Not applicable as all entities are registered as GO and GOP.	0	0		n/a

Disclaimer: This information has been prepared as input into BC Hydro's thirteenth assessment report on Mandatory Reliability Standards and is based on information available to BC Hydro as of the date sent. It should not be relied upon for any other purpose.

Toba Montrose General Partnership, Jimmie Creek Limited Partnership, Dokie General Partnership, Upper Lillooet River Power, Harrison Hydro Limited Partnership (GO/GOP)

Assessment Number	FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 8, 2020 Glossary of Terms	Acronym (If Applicable)	FERC Approved New/Revised/Retired NERC Term Definitions against Terms and Definitions listed in Columns "D" and "E" (changes to definition indicated by red text; deletions are not indicated)	Current BCUC Adopted Terms from October 8, 2020 Glossary of Terms	Current BCUC Adopted Definition from October 8, 2020 Glossary of Terms	FERC Approval Date of New/Revised/Retired NERC Term and Definition	Effective Date of New/Revised/Retired NERC Term and Definition in United States	Stakeholder Comments (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental Cost Associated with Revised/New Term and Definition, if any ($). (Press Alt-Enter to insert a carriage return in a cell)		BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time ($)	Cost Ongoing ($)	
11	**Remedial Action Scheme** *Glossary term is specific to the currently adopted CIP-002-3/5.1, CIP-003-5, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, EOP-004-3, FAC-010-3, FAC-011-3, MOD-029-2a, MOD-030-3, NUC-001-3, PRC-001-1.1(ii), PRC-004-5(i), PRC-004-WECC-2, PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-4, PRC-024-2, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a standards	**RAS**	N/A	**Retired**	See "Special Protection System"	31-Mar-2017	31-Mar-2017	**Innergex Compliance Team: no issue with retirement**	**0**	**0**	**No issue**
11	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the currently adopted CIP-002-3/5.1, CIP-003-5, CIP-004-6, CIP-005-5, CIP-006-6, CIP-007-6, CIP-008-5, CIP-009-6, CIP-010-2, CIP-011-2, EOP-004-3, FAC-010-3, FAC-011-3, IRO-002-4, IRO-005-3.1a, IRO-008-2, IRO-010-2, MOD-029-2a, MOD-030-3, PRC-001-1.1(ii), PRC-004-5(i), PRC-005-2(i), PRC-005-6, PRC-015-1, PRC-016-1, PRC-017-1, PRC-021-1, PRC-023-2, PRC-023-4, PRC-024-2, PRC-025-1, TOP-001-3, TOP-002-4, TOP-003-3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a standards	**SPS**	N/A	**Retired**	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	31-Mar-2017	31-Mar-2017	**Innergex Compliance Team: no issue with retirement**	**0**	**0**	**No issue**
10	**Special Protection System (Remedial Action Scheme)** *Glossary term is specific to the PRC-010-2 standard which is held in abeyance in B.C., and is indirectly referenced from the PRC-006-2 (also held in abeyance in B.C.) via the term Special Protection System - SPS, as well as the currently adopted CIP-002-3/5.1, EOP-004-2, FAC-010-2.1, FAC-011-2, IRO-005-3.1a, MOD-029-1a, MOD-030-2, NUC-001-2/3, PRC-001-1.1, PRC-004-WECC-1, PRC-005-2(i), PRC-015-0, PRC-016-0.1, PRC-017-0, PRC-021-1, PRC-023-1/2/3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a	**SPS**	See "Remedial Action Scheme"	Special Protection System (Remedial Action Scheme)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	23-Jun-16	01-Apr-17	**Innergex Compliance Team: no issue**	**0**	**0**	**Coincide with effective date of PRC-010-2 standard after BCUC adoption**
9	**Remedial Action Scheme** *Glossary term is specific to the new PRC-010-2 standard, and is indirectly referenced from the new PRC-006-2 and PRC-005-2(i) standards (via the term Special Protection System - SPS) as well as the currently adopted CIP-002-3/5.1, EOP-004-2, FAC-010-2.1, FAC-011-2, IRO-005-3.1a, MOD-029-1a, MOD-030-2, NUC-001-2/3, PRC-001-1.1, PRC-004-WECC-1, PRC-015-0, PRC-016-0.1, PRC-017-0, PRC-021-1, PRC-023-1/2/3, TOP-005-2a, TPL-001-0.1, TPL-002-0b, TPL-003-0b, TPL-004-0a	**RAS**	Please refer to the NERC Glossary of Terms for the definition as it is too long to replicate here.	**Remedial Action Scheme**	"See Special Protection System" which is defined as: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.	19-Nov-15	01-Apr-17	**Innergex Compliance Team: no issue**	**0**	**0**	**Coincide with effective date of PRC-010-2 standard after BCUC adoption**
9	**Under Voltage Load Shedding Program** *Glossary term is specific to the new PRC-010-2 standard	**UVLS Program**	An automatic load shedding program, consisting of distributed relays and controls, used to mitigate under voltage conditions impacting the Bulk Electric System (BES), leading to voltage instability, voltage collapse, or Cascading. Centrally controlled under voltage-based load shedding is not included.	**New**	N/A	19-Nov-15	01-Apr-17	**Innergex Compliance Team: no issue as PRC-010-2 is not applicable to the GO/GOP functions**	**0**	**0**	**Coincide with effective date of PRC-010-2 standard after BCUC adoption**

BC Hydro
Power smart

BC Hydro Mandatory Reliability Standards
Planning Coordinator Assessment Report

Appendix D

Draft Order

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
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ORDER NUMBER
R-xx-xx

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

and

British Columbia Hydro and Power Authority (BC Hydro)
Filing for Approval of Mandatory Reliability Standards
Planning Coordinator Assessment Report

BEFORE:
Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On May 31, 2021, British Columbia Hydro and Power Authority (**BC Hydro**) filed its Mandatory Reliability Standards (**MRS**) Planning Coordinator Assessment Report (**PC Report**) with the British Columbia Utilities Commission (**BCUC**) pursuant to section 125.2(3) of the *Utilities Commision Act* (**UCA**) which assesses those reliability standards and defined terms set out in the North American Electric Reliability Corporation (**NERC**) Glossary of Terms (**Glossary**) that reference the Planning Coordinator (**PC**) function and which have not been previously adopted in British Columbia (**B.C.**);

B. In BCUC Order No. R-41-13, the BCUC determined that a consideration of the implementation of the PC function in B.C. was beyond the scope of the Assessment Report No. 6 process undertaken that year and confirmed this would be considered by separate process. As a result, the BCUC held in abeyance any reliability standards or requirements, as applicable, that referenced the PC function and that could not be performed without an entity being registered as a PC pursuant to BCUC Order Nos. R-41-13, R-32-14, R-38-15, R-32-16, R-39-17 and R-33-18;

C. The BCUC has requested that BC Hydro assess all reliability standards referencing the PC function which are held in abeyance or new in the 2020 assessment period of December 1, 2019 to November 30, 2020 (**2020 Assessment Period**);

D. Accordingly, in this PC Report BC Hydro has assessed the adoption of 12 standards which reference the PC function that are either new in the 2020 Assessment Period or are held in abeyance in B.C. (collectively, the

PC Standards), the retirement of the FAC-013-1 standard and the adoption of 4 defined terms contained in the NERC Glossary of Terms (**PC Terms**) that have been held in abeyance;

E. As a result of this assessment, BC Hydro recommends that 11 of the 12 PC Standards and all four PC Terms are suitable for adoption in B.C. at this time. In addition, BC Hydro recommends the retirement of the FAC-013-1 standard;

F. BC Hydro also recommends that, in connection with the adoption of TPL-001-5.1 and TPL-007-4, the BCUC adopt the B.C. specific versions of the Implementation Plans associated with these standards that have been adopted by the Federal Energy Regulatory Commission in the United States. BC Hydro provided B.C. specific versions of the TPL-001-5.1 Implementation Plan and the TPL-007-4 Implementation Plan in the PC Report (together, the **Implementation Plans**);

G. By Order No. R-XX-20 dated MM DD, 2021, BC Hydro was directed to publish a notice of process to the public and entities registered in the MRS Program (Entities) for consideration of the recommendations found in PC Report along with the established regulatory timetable;

H. On MM DD, 2021, comments were received from xxxxxx;

I. Pursuant to section 125.2(6) of the UCA, the BCUC must adopt the reliability standards addressed in the PC Report if the BCUC considers that the reliability standards are required to maintain or achieve consistency in B.C. with other jurisdictions that have adopted the reliability standards; and

J. The BCUC has reviewed and considered the PC Report and the recommendations made therein [as well as the comments received by Entities] and considers that the adoption of the PC Standards, the PC Terms and the Implementation Plans and the retirement of FAC-013-1 is warranted. Although not assessed by BC Hydro, the BCUC considers that the compliance provisions of the reliability standards (**Compliance Provisions**) should be adopted to maintain compliance monitoring consistency with other jurisdictions that have adopted the reliability standards with the Compliance Provisions. The BCUC considers it appropriate to provide effective dates for BC entities to come into compliance with the PC Standards and PC Terms adopted in this Order.

NOW THEREFORE pursuant to section 125.2(3) and 125.2(6) of the UCA, which, among other things, provides the BCUC exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in B.C., the BCUC Orders as follows:

1. Eleven out of the 12 PC Standards assessed in the PC Report are adopted with effective dates in Table 1 of Attachment A to this Order. Each standard to be superseded by a PC Standard adopted in this Order shall remain in effect until the effective date of the PC Standard superseding it.

2. Reliability Standard FAC-013-1 is retired as of the effective date as identified in Table 1 of Attachment A to this Order.

3. Attachment B to this Order lists all the reliability standards adopted by the BCUC and effective in B.C. as of the dates shown. The effective dates for the reliability standards listed in Attachment B supersede the effective dates that were included in any similar list appended to any previous Order of the BCUC.

4. Individual requirements within reliability standards that incorporate, by reference, reliability standards that have not been adopted by the BCUC, are of no force and effect in B.C. and individual requirements or sub-requirements within reliability standards, which the BCUC has adopted but for which the BCUC has not determined an effective date, are of no force and effect in B.C.
5. Defined terms set out in the reliability standards bear the same meaning as those set out in the NERC Glossary dated October 8, 2020. Other terms in the NERC Glossary, which do not include a United States FERC approval date on or before November 30, 2020, are of no force or effect in B.C. Each glossary term to be superseded by a PC Term adopted in this Order shall remain in effect until the effective date of the PC Term superseding it. The effective date of each of the PC Terms adopted by this Order is the date in Table 2 of Attachment A to this Order.
6. All defined terms listed in the NERC Glossary attached as Appendix B to this Order are in effect in B.C. as of the effective dates indicated. The effective dates for the PC Terms listed in Attachment C supersede the effective dates that were included in any similar list appended to any previous Order made by the BCUC.
7. The Compliance Provisions as defined in the Rules of Procedure for Reliability Standards in British Columbia that accompany each of the adopted reliability standards, are approved in the form directed by the BCUC and as amended from time to time.
8. The BC specific versions of the TPL-001-5.1 Implementation Plan and the TPL-007-4 Implementation Plan are adopted in the form directed by the BCUC and as amended from time to time, and effective as indicated in Attachment D to this Order. The BC specific versions of the TPL-001-5.1 Implementation Plan and the TPL-007-4 Implementation Plan will be posted on the WECC website with links from the BCUC website.
9. The PC Standards in their written form are adopted as set out in Attachment E to this Order.
10. The reliability standards adopted in BC will be posted on the WECC website with a link from the BCUC website.
11. Entities subject to Mandatory Reliability Standards are required to report to the BCUC and may, on a voluntary basis, report to NERC or to FERC.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachments

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

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded[1]
1	EOP-003-2	Load Shedding Plans	Not recommended for adoption in B.C.[2]	Revised (held in abeyance)	EOP-003-1/ TOP-001-1a R8/ TOP-007-0 R3/ TOP-008-1 R1
2	FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	Not recommended for adoption in B.C. Instead, recommend accelerated retirement of preceding FAC-013-1 reliability standard immediately after BCUC approval.[3]	Retired (held in abeyance)	FAC-013-1
3	MOD-032-1	Data for Power System Modeling and Analysis	**R1:** The first day of the first calendar quarter that is 12 months after BCUC adoption. **R2 - R4:** The first day of the first calendar quarter that is 24 months after BCUC adoption.	New (held in abeyance)	MOD-010-0/MOD-012-0

1 BCUC approved reliability standard or reliability standard held in abeyance by the BCUC to be superseded by the replacement or revised reliability standard assessed.

2 The EOP-003-2 reliability standard will be superseded by the adoption of the PRC-010-2 reliability standard which is recommended for adoption under this report.

3 FAC-013-2 was retired in the U.S. as of December 14, 2020 per FERC Order No. 873.

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded[1]
4	MOD-033-2	Steady-State and Dynamic System Model Validation	The first day of the first calendar quarter, 36 months after BCUC adoption. Initial Performance of Periodic Requirements: MOD-033-2, Requirement R1, parts 1.1 and 1.2 include periodic components for validation that contain time parameters for subsequent and recurring iterations of implementing the requirement, specified as, ". . . at least once every 24 calendar months . . .", and responsible entities shall comply initially with those periodic components within 24 calendar months after the effective date of MOD-033-2.	New	n/a – MOD-033-1 standard in abeyance
5	PRC-006-4	Automatic Underfrequency Load Shedding	The first day of the first calendar quarter, 36 months after BCUC adoption.	Revised	PRC-007-0/PRC-009-0
6	PRC-010-2	Undervoltage Load Shedding	The first day of the first calendar quarter, three months after BCUC adoption.	Revised (held in abeyance)	EOP-003-1/PRC-010-0/ PRC-021-1/ PRC-022-1

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded[1]
7	PRC-012-2 Requirements R1: Attachment 1, Section II Parts 6(d) and 6(e) R2: Attachment 2, Section I Parts 7(d) and 7(e), and R4	Remedial Action Schemes	No change to the October 1, 2021 PRC-012-2 effective date in B.C. and B.C. specific PRC-012-2 Implementation Plan adopted per BCUC Order No. R-33-18 with the following exceptions pending BCUC approval. **R1 Attachment 1, Section II Parts 6(d) and 6(e) and** **R2 Attachment 2, Section I Parts 7(d) and 7(e):** Pending BCUC adoption of these requirements, align with the October 1, 2021 effective date of PRC-012-2 in B.C. **R4:** Pending BCUC adoption of this requirement, align with the FERC approved NERC PRC-012-2 implementation plan as follows: For existing RAS, initial performance of obligations under Requirement R4 must be completed within five full calendar years after the October 1, 2021 effective date of PRC-012-2 in B.C. For new or functionally modified RAS, the initial performance of Requirement R4 must be completed within five full calendar years after the date that the RAS is approved by the reviewing RC(s) under Requirement R3.	Reliability standard is currently adopted with specified requirements held in abeyance	PRC-015-1/PRC-016-1

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded[1]
8	PRC-023-2 Requirements R1 – R6 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6	Transmission Relay Loadability	No change to existing PRC-023-2 effective dates in B.C. with the following exception pending BCUC approval. **R1-R6 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1:** Align with implementation timeframe of PRC-023-4 Requirements R1 – R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6 pending BCUC adoption.	Reliability standard is currently adopted with specified requirements held in abeyance	n/a - PRC-023-2 Requirements R1 – R6 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of Requirement R1 as identified by the PC per Requirement R6 held in abeyance in B.C.
9	PRC-023-4 Requirements R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6	Transmission Relay Loadability	No change to existing PRC-023-4 effective dates in B.C. with the following exception pending BCUC approval. **R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, 4.2.1.6, and for R6:** The first day of the first calendar quarter, 24 months after BCUC adoption.	Reliability standard is currently adopted with specified requirements held in abeyance	n/a - PRC-023-4 Requirements R1-R5 for circuits per Applicability sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 and Requirement R6 held in abeyance in B.C.
10	PRC-026-1	Relay Performance During Stable Power Swings	**R1:** The first day of the first full calendar year, 12 months after BCUC adoption. **R2 - R4:** The first day of the first full calendar year, 36 months after BCUC adoption.	New (held in abeyance)	n/a – standard in abeyance

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded[1]
11	TPL-001-4 Requirement 7	Transmission System Planning Performance Requirements	No change to existing TPL-001-4 effective dates in B.C. with the following exception pending BCUC approval. **R7:** The first day of the first calendar quarter, three months after BCUC adoption.	Reliability standard is currently adopted with specified requirements held in abeyance	n/a - TPL-001-4 Requirement 7 held in abeyance in B.C.
12	TPL-001-5.1	Transmission System Planning Performance Requirements	The first day of the first calendar quarter, 36 months after the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC adoption of the TPL-001-5.1 and MOD-032-1 standards. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C. specific TPL-001-5.1 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards.	Revised	TPL-001-4

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded[1]
13	TPL-007-4	Transmission System Planned Performance for Geomagnetic Disturbance	The first day of the first calendar quarter, six months after BCUC adoption. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C. specific TPL-007-4 Implementation Plan be incorporated into the B.C. MRS program pursuant to an order of the BCUC providing for the administration of adopted reliability standards.	New	n/a - TPL-007-3 standard – in abeyance

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

	NERC Glossary Term	Acronym	Effective Date	BCUC Approved Term to be Replaced or Retired
1	Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	GMD	Coincide with the effective date of the TPL-007-4 standard in B.C. pending BCUC adoption.	n/a – Glossary Term in abeyance
2	Remedial Action Scheme	RAS	Coincide with the effective date of the PRC-010-2 standard in B.C. pending BCUC adoption.	Remedial Action Scheme
3	Special Protection System (Remedial Action Scheme)	SPS	Coincide with the effective date of the PRC-010-2 standard in B.C. pending BCUC adoption.	Special Protection System (Remedial Action Scheme)
4	Undervoltage Load Shedding Program	UVLS Program	Coincide with the effective date of the PRC-010-2 standard in B.C. pending BCUC adoption.	n/a – Glossary Term in abeyance

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
BAL-001-2	Real Power Balancing Control Performance	R-14-16	July 1, 2016
BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	R-21-19	April 1, 2020
BAL-002-WECC-2a	Contingency Reserve	R-39-17	July 26, 2017
BAL-003-1.1[1]	Frequency Response and Frequency Bias Setting	R-32-16A	October 1, 2016
BAL-003-2	Frequency Response and Frequency Bias Setting		
BAL-004-WECC-3	Automatic Time Error Correction	R-21-19	January 1, 2020
BAL-005-1	Balancing Authority Control	R-33-18	October 1, 2019
CIP-002-5.1a	Cyber Security — BES Cyber System Categorization	R-33-18	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-003-8	Cyber Security — Security Management Controls	R-19-20	October 1, 2020 and as per BC-specific Implementation Plan
CIP-004-6	Cyber Security — Personnel & Training	R-39-17	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-005-5[1]	Cyber Security – Electronic Security Perimeter(s)	R-38-15	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-005-6	Cyber Security – Electronic Security Perimeter(s)	R-19-20	April 1, 2023 and as per B.C.-specific Implementation Plan

1 Reliability standard is superseded by the revised/replacement reliability standard listed immediately below it as of the effective date(s) of the revised/replacement reliability standard.

Standard	Name	BCUC Order Adopting	Effective Date
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems	R-39-17	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-007-6	Cyber Security — System Security Management	R-39-17	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-008-5[1]	Cyber Security – Incident Reporting and Response Planning	R-38-15	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-008-6	Cyber Security – Incident Reporting and Response Planning	R-19-20	April 1, 2023
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems	R-39-17	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-010-2[1]	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-39-17	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-010-3	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-19-20	April 1, 2023 and as per B.C.-specific Implementation Plan
CIP-011-2	Cyber Security – Information Protection	R-39-17	October 1, 2018 and as per B.C.-specific Implementation Plan
CIP-012-1	Cyber Security – Communications between Control Centers		
CIP-013-1	Cyber Security - Supply Chain Risk Management	R-19-20	April 1, 2023 and as per B.C.-specific Implementation Plan
CIP-014-2	Physical Security	R-32-16A	October 1, 2017 and as per B.C.-specific Implementation Plan
COM-001-3	Communications	R-39-17	R1, R2: October 1, 2017 R3-R13: October 1, 2018
COM-002-4	Operating Personnel Communications Protocols	R-32-16A	April 1, 2017

Standard	Name	BCUC Order Adopting	Effective Date
EOP-003-1[2]	Load Shedding Plans	G-67-09	November 1, 2010
EOP-004-4	Event Reporting	R-21-19	October 1, 2020
EOP-005-3	System Restoration and Blackstart Resources	R-21-19	October 1, 2020
EOP-006-3	System Restoration Coordination	R-21-19	October 1, 2020
EOP-008-2	Loss of Control Center Functionality	R-21-19	October 1, 2020
EOP-010-1	Geomagnetic Disturbance Operations	R-38-15	R1, R3: October 1, 2016 R2: October 1, 2017
EOP-011-1	Emergency Operations	R-39-17	October 1, 2018
FAC-001-3	Facility Interconnection Requirements	R-33-18	October 1, 2019
FAC-002-2[1]	Facility Interconnection Studies	R-38-15	October 1, 2015
FAC-002-3	Facility Interconnection Studies		
FAC-003-4	Transmission Vegetation Management	R-39-17	October 1, 2017
FAC-008-3	Facility Ratings	R-32-14	August 1, 2015 R4 and R5: Retired January 21, 2014[3]
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	Establish and Communicate Transfer Capability	G-67-09	November 1, 2010 Retired:
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011

2 Reliability standard is superseded by the EOP-011-1 standard in conjunction with Requirement 1 of the PRC-010-2 reliability standard as of the effective date of PRC-010-2 in B.C.

3 On November 21, 2013, FERC Order 788 (referred to as Paragraph 81) approved the retiring of the reliability standard requirements.

Standard	Name	BCUC Order Adopting	Effective Date
FAC-501-WECC-2	Transmission Maintenance	R-21-19	October 1, 2019
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-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-002-6	Reliability Coordination – Monitoring and Analysis	R-19-20	April 1, 2021
IRO-005-3.1a[4,]	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-3	Qualified Transfer Path Unscheduled Flow (**USF**) Relief	R-19-20	January 1, 2021
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-010-2[1]	Reliability Coordinator Data Specification and Collection	R-39-17	April 1, 2019
IRO-010-3	Reliability Coordinator Data Specification and Collection		
IRO-014-3	Coordination Among Reliability Coordinators	R-39-17	October 1, 2017
IRO-017-1	Outage Coordination	R-39-17	October 1, 2020

4 Refer to “IRO and TOP Reliability Standards Supersession Mapping” section below.

Standard	Name	BCUC Order Adopting	Effective Date
IRO-018-1(i)	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities	R-33-18	April 1, 2020
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[5]	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0[5]	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 With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021
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

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

Standard	Name	BCUC Order Adopting	Effective Date
MOD-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[1]	Demand and Energy Data	R-39-17	April 1, 2018
MOD-031-3	Demand and Energy Data		
MOD-032-1	Data for Power System Modeling and Analysis		
MOD-033-2	Steady-State and Dynamic System Model Validation		
NUC-001-3[1]	Nuclear Plant Interface Coordination	R-38-15	January 1, 2016
NUC-001-4	Nuclear Plant Interface Coordination		
PER-003-2	Operating Personnel Credentials	R-21-19	April 1, 2020
PER-005-2	Operations Personnel Training	R-38-15	R1-R4, R6: October 1, 2016 R5: October 1, 2017
PER-006-1[6]	Specific Training for Personnel	R-21-19	October 1, 2021
PRC-001-1.1(ii) [7]	System Protection Coordination	R-32-16A	October 1, 2016

6 Reliability standard will supersede PRC-001-1.1(ii) R1 as of the effective date of PER-006-1.

7 PRC-001-1.1(ii) Requirement 1 will be superseded by PER-006-1 as of the effective date of PER-006-1; PRC-001-1.1(ii) Requirements 3 and 4 will be superseded by PRC-027-1 as of the effective date of PRC-027-1; and, the rest of PRC-001-1.1(ii) has been superseded by other reliability standards as of April 1, 2021.

Standard	Name	BCUC Order Adopting	Effective Date
PRC-002-2	Disturbance Monitoring and Reporting Requirements	R-32-16A	R1, R5: April 1, 2017 R2-R4, R6-R11: staged as per B.C.-specific Implementation Plan R12: July 1, 2017
PRC-004-5(i)	Protection System Misoperation Identification and Correction	R-32-16A	October 1, 2017
PRC-004-WECC-2	Protection System and Remedial Action Scheme Misoperation	R-39-17	October 1, 2017 Retirement: September 30, 2021
PRC-005-1.1b[1,8]	Transmission and Generation Protection System Maintenance and Testing	R-32-14	January 1, 2015
PRC-005-2[1,8]	Protection System Maintenance	R-38-15	R1, R2, R5: October 1, 2017 R3, R4: staged as per B.C.-specific Implementation Plan
PRC-005-2(i) [1,8]	Protection System Maintenance	R-32-16A	R1, R2, R5: October 1, 2017 R3, R4: staged as per B.C.-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-006-4	Automatic Underfrequency Load Shedding		
PRC-007-0[9]	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0[8]	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010

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

9 Reliability standard will be superseded by PRC-006-4 if adopted in B.C.

Standard	Name	BCUC Order Adopting	Effective Date
PRC-009-0[9]	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	November 1, 2010
PRC-010-0[1]	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	November 1, 2010 R2: Retired January 21, 2014
PRC-010-2	Under Voltage Load Shedding		
PRC-011-0[8]	Undervoltage Load Shedding system Maintenance and Testing	G-67-09	November 1, 2010
PRC-012-2	Remedial Action Schemes	R-33-18	October 1, 2021 R1 Attachment 1, Section II Parts 6(d) and 6(e): R2 Attachment 2, Section I Parts 7(d) and 7(e): R4:
PRC-015-1[10]	Remedial Action Scheme Data and Documentation	R-39-17	October 1, 2017
PRC-016-1[10]	Remedial Action Scheme Misoperations	R-39-17	October 1, 2017
PRC-017-1[8]	Remedial Action Scheme Maintenance and Testing	R-39-17	October 1, 2017
PRC-018-1[11]	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-32-16A With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021

[10] Reliability standard is superseded by PRC-012-2 as of the PRC-012-2 effective date.

[11] Reliability standard is superseded by PRC-002-2 as of the PRC-002-2 effective date.

Standard	Name	BCUC Order Adopting	Effective Date
PRC-021-1[12]	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010
PRC-022-1[12]	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010 R2: Retired January 21, 2014[3]
PRC-023-2[1, 13]	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 that meet Criterion 6 of R1: R6: For circuits identified by sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6 that meet Criterion 6 of R1:
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-025-2 R1 is completely effective in B.C. 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:
PRC-024-2[1]	Generator Frequency and Voltage Protective Relay Settings	R-32-16A With revised effective dates by Order R-14-20	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by April 1, 2021
PRC-024-3	Frequency and Voltage Protection Settings for Generating Resources		

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

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

Standard	Name	BCUC Order Adopting	Effective Date
PRC-025-2	Generator Relay Loadability	R-21-19	October 1, 2019 and staged per B.C. specific Implementation Plan
PRC-026-1	Relay Performance During Stable Power Swings		
PRC-027-1[14]	Coordination of Protection Systems for Performance During Faults	R-21-19	October 1, 2021
TOP-001-1a[4]	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-001-4	Transmission Operations	R-33-18 With revised effective dates by Order R-14-20	April 1, 2021
TOP-002-4	Operations Planning	R-39-17 With revised effective dates by Order R-14-20	April 1, 2021
TOP-003-3[1]	Operational Reliability Data	R-39-17	April 1, 2019
TOP-003-4	Operational Reliability Data		
TOP-007-0[4]	Reporting System Operating Unit (**SOL**) and Interconnection Reliability Operating Limit (**IROL**) Violations	G-67-09	November 1, 2010
TOP-008-1[4]	Response to Transmission Limit Violations	G-67-09	November 1, 2010
TOP-010-1(i)	Real-time Reliability Monitoring and Analysis Capabilities	R-33-18 With revised effective dates by Order R-14-20	April 1, 2021

[14] Reliability standard will supersede PRC-001-1.1(ii) Requirements 3 and 4 as of the effective date of PRC-027-1.

Standard	Name	BCUC Order Adopting	Effective Date
TPL-001-4[1]	Transmission System Planning Performance Requirements	R-27-18A	R1: July 1, 2019 R2-R6, R8: July 1, 2020 R7:
TPL-001-5.1	Transmission System Planning Performance Requirements		
TPL-007-4	Transmission System Planned Performance for Geomagnetic Disturbance		
VAR-001-5	Voltage and Reactive Control	R-21-19	October 1, 2019
VAR-002-4.1	Generator Operation for Maintaining Network Voltage Schedules	R-33-18	October 1, 2018
VAR-501-WECC-3.1	Power System Stabilizer (**PSS**)	R-33-18	October 1, 2020 R3: For units placed into service after the effective date: January 1, 2021 For units placed into service prior to the effective date: January 1, 2024

IRO and TOP Reliability Standards Supersession Mapping

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

IRO-005-3.1a — Reliability Coordination - Current Day Operations

TOP-001-1a — Reliability Responsibilities and Authorities

TOP-007-0 — Reporting System Operating Limit (**SOL**) and Interconnection Reliability Operating Limit (**IROL**) Violations

TOP-008-1 — Response to Transmission Limit Violations

Standard 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
Requirement R8	IRO-001-4 IRO-002-4
Requirement R9	IRO-002-4 IRO-010-2
Requirement R10	IRO-009-1 TOP-001-4
Requirement R11	MOD-001-2, Requirement R2 (pending FERC adoption in the U.S. and subsequent assessment and adoption in B.C.)
Requirement R12	IRO-008-2

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

Standard TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	
Requirement Being Superseded	**Superseding BCUC Approved Standard(s)**
Requirement R1	IRO-008-2 TOP-001-4

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 R2	IRO-009-2 TOP-001-4
Requirement R3	EOP-003-2, Requirement 1 (adoption held in abeyance in B.C. due to PA/PC dependencies) IRO-009-2
Requirement R4	IRO-008-2

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

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

Updated , 2020

Introduction:

This document is to be used in conjunction with the NERC Glossary dated October 8, 2020.

- The NERC Glossary terms listed in Table 1 below are effective in B.C. on the date specified in the "Effective Date" column.
- Table 2 below outlines the adoption history by the BCUC of the NERC Glossaries in B.C.
- Any NERC Glossary terms and definitions in the NERC Glossary that are not approved by FERC on or before November 30, 2020 are of no force or effect in B.C.
- Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in B.C.
- The 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 B.C.

Table 1 B.C. Effective Date Exceptions to Definitions in the October 8, 2020 Version of the NERC Glossary

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Actual Frequency (F_A)	-	Report No. 11	R-33-18	Adoption	October 1. 2019
Actual Net Interchange (NI_A)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Automatic Time Error Correction (I_{ATEC})	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Adjacent Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Alternative Interpersonal Communication	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Area Control Error (from NERC section of the Glossary)	ACE	Report No. 7	R-32-14	Adoption	October 1, 2014
Area Control Error (from the WECC Regional Definitions section of the Glossary)	ACE	Report No. 7	R-32-14	Retirement	October 1, 2014
Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Attaining Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Automatic Generation Control	AGC	Report No. 11	R-33-18	Adoption	October 1, 2019

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Automatic Time Error Correction	-	Report No. 7	R-32-14	Adoption	October 1, 2014
Balancing Authority	-	Report No. 11	R-33-18	Adoption	January 1, 2019
Balancing Contingency Event[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
BES Cyber Asset[2]	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
BES Cyber Asset	BCA	Report No. 10	R-39-17	Adoption	October 1, 2018
BES Cyber System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.

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

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

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
BES Cyber System Information	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Blackstart Capability Plan	-	Report No. 7	R-32-14	Retirement	August 1, 2015
Blackstart Resource[2]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Blackstart Resource	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Bulk Electric System	BES	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System[2]	-	Report No. 8	R-38-15	-	October 1, 2015
Bulk-Power System	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Bus-tie Breaker	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Cascading	-	Report No. 10	R-39-17	Adoption	October 1, 2017
CIP Exceptional Circumstance	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
CIP Senior Manager	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Composite Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Composite Protection System	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Contingency Event Recovery Period[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contingency Reserve Restoration Period[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Contributing Schedule (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Control Center	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Critical Assets	-	Report No. 9	R-32-16A	Retirement	September 30, 2018
Critical Cyber Assets	-	Report No. 9	R-32-16A	Retirement	September 30, 2018
Cyber Assets	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Cyber Security Incident	-	Report No. 13	R-19-20	Adoption	April 1, 2023
Demand-Side Management	DSM	Report No. 9	R-32-16A	Adoption	October 1, 2016

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Dial-up Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Distribution Provider	DP	Report No. 10	R-39-17	Adoption	October 1, 2017
Disturbance	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Dynamic Interchange Schedule or Dynamic Schedule	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Electronic Access Control or Monitoring Systems	EACMS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Electronic Access Point	EAP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Electronic Security Perimeter	ESP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Element	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Energy Emergency[2]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Energy Emergency	-	Report No. 11	R-33-18	Retirement	October 1, 2018
External Routable Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Frequency Bias Setting	-	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Measure	FRM	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Frequency Response Obligation	FRO	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Frequency Response Sharing Group	FRSG	Report No. 8	R-38-15	Adoption	Align with earliest effective date of BAL-003-1 standard where this term is referenced
Generator Operator	GOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Generator Owner	GO	Report No. 10	R-39-17	Adoption	October 1, 2017
Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment	GMD				
Interactive Remote Access	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interchange Authority	IA	Report No. 10	R-39-17	Adoption	October 1, 2017
Interchange Meter Error (IME)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Interconnected Operations Service	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection Reliability Operating Limit	IROL	Report No. 6	R-41-13	Adoption	December 12, 2013

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Intermediate Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Intermediate System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interpersonal Communication	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Load-Serving Entity	LSE	Report No. 10	R-39-17	Adoption	October 1, 2017
Long-Term Transmission Planning Horizon	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Minimum Vegetation Clearance Distance	MVCD	Report No. 7	R-32-14	Adoption	August 1, 2015
Misoperation	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
Most Severe Single Contingency[1]	MSSC	Report No. 10	R-39-17	Adoption	January 1, 2018
Native Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Non-Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Non-Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Operating Instruction	-	Report No. 9	R-32-16A	Adoption	April 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Operational Planning Analysis[2]	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Operational Planning Analysis[2]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Operational Planning Analysis[2]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Operational Planning Analysis	OPA	Report No. 12	R-21-19	Adoption	October 1, 2021
Operations Support Personnel	-	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 5 of the PER-005-2 standard where this term is referenced
Physical Access Control Systems	PACS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Physical Security Perimeter	PSP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Planning Assessment	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Planning Authority	PA	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Point of Receipt	POR	Report No. 10	R-39-17	Adoption	October 1, 2017
Pre-Reporting Contingency Event ACE Value[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Protected Cyber Assets[2]	PCA	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Protected Cyber Assets	PCA	Report No. 10	R-39-17	Adoption	October 1, 2018
Protection System	-	Report No. 6	R-41-13	Adoption	January 1, 2015 for each entity to modify its protection system maintenance and testing program to reflect the new definition (to coincide with recommended effective date of PRC-005-1b) and until the end of the first complete maintenance and testing cycle to implement any additional maintenance and testing for battery chargers as required by that entity's program.
Protection System Coordination Study	-	Report No. 12	R-21-19	Adoption	October 1, 2021

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC 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-005-6)*	PSMP	Report No. 10	R-39-17	Adoption	October 1, 2019
Pseudo-Tie[2]	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Pseudo-Tie	-	Report No. 11	R-33-18	Adoption	January 1, 2019
Qualified Controllable Device (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Qualified Path (WECC Regional Term)	-	Report No. 13	R-19-20	Adoption	January 1, 2021
Qualified Transfer Path (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Qualified Transfer Path Curtailment Event (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Reactive Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real-time Assessment[2]	-	Report No. 6	R-41-13	Adoption	January 1, 2014

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Real-time Assessment[2]	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Real-time Assessment	RTA	Report No. 12	R-21-19	Adoption	October 1, 2021
Reliability Adjustment Arranged Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Reliability Coordinator	RC	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliability Directive	-	Report No. 9	R-32-16A	Retirement	July 18, 2016
Reliability Standard[2]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliability Standard	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reliable Operation[2]	-	Report No. 8	R-32-14	Adoption	October 1, 2015
Reliable Operation	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Relief Requirement (WECC Regional Term)	-	Report No. 8	R-38-15	Adoption	Align with effective date of IRO-006-WECC-2 standard where this term is referenced
Relief Requirement (WECC Regional Term)	-	Report No. 13	R-19-20	Retirement	December 31, 2020
Remedial Action Scheme[2]	RAS	Report No. 1	G-67-09	Adoption	June 4, 2009
Remedial Action Scheme	RAS				
Removable Media[2]	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Removable Media	-	Report No. 12	R-21-19	Adoption	October 1, 2019
Reporting ACE	-	Report No. 11	R-33-18	Adoption	October 1, 2019

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC 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 (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Reportable Cyber Security Incident	-	Report No. 13	R-19-20	Adoption	April 1, 2023
Request for Interchange	RFI	Report No. 8	R-38-15	Adoption	October 1, 2015
Reserve Sharing Group	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reserve Sharing Group Reporting ACE[1]	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Resource Planner	RP	Report No. 10	R-39-17	Adoption	October 1, 2017
Scheduled Net Interchange (NI_S)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
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) [2]	SPS	Report No. 1	G-67-09	Adoption	June 4, 2009

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Special Protection System (Remedial Action Scheme)	SPS				
Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
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 (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) as reference is made to the term Control Center as part of the definition of System Operator. The term Control Center is in turn referenced from the CIP Version 5 standards.
Total Internal Demand	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Transient Cyber Asset[2]	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Transient Cyber Asset	TCA	Report No. 12	R-21-19	Adoption	October 1, 2019
Transmission Customer	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Transfer Distribution Factor (WECC Regional Term)	TDF	Report No. 13	R-19-20	Retirement	December 31, 2020
Transmission Operator	TOP	Report No. 10	R-39-17	Adoption	October 1, 2017

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
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
Under Voltage Load Shedding Program	-	Report No. 9		-	To be determinedError! Bookmark not defined.
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
Undervoltage Load Shedding Program	UVLS Program	Planning Coordinator			
Vegetation Inspection	-	Report No. 7	R-32-14	Adoption	August 1, 2015

Table 2 NERC Glossary Adoption History in B.C.

NERC Glossary of Terms Version Date	Assessment Report Number	BCUC Order Adoption Date	BCUC Order Adopting	Effective Date
February 12, 2008	Report No. 1	June 4, 2009	G-67-09	1. The NERC Glossaries listed became effective as of the date of the respective BCUC Orders adopting them. See the exception of the BAL-001-2 Glossary Terms within the NERC Glossary dated December 7, 2015.1 2. Specific effective dates of new and revised NERC Glossary terms adopted in a BCUC Order appear in attachments to the Order. Each Glossary term to be superseded by a revised Glossary term adopted in the Order shall remain in effect until the effective date of the Glossary term superseding it. 3. NERC Glossary terms which have not been approved by FERC are of no force or effect in B.C. 4. Any NERC Glossary terms that have been remanded or retired by NERC are of no force or effect in B.C., with the exception of those remanded or retired NERC Glossary terms which have not yet been retired in B.C. 5. The Electric Reliability Council of Texas, Northeast Power Coordinating Council and Reliability First regional definitions listed at the end of the NERC Glossary of Terms are of no force or effect in B.C.
April 20, 2010	Report No. 2	November 10, 2010	G-167-10	
August 4, 2011	Report No. 3	September 1, 2011	G-162-11 Replacing G-151-11	
December 13, 2011	Report No. 5	January 15, 2013	R-1-13	
December 5, 2012	Report No. 6	December 12, 2013	R-41-13	
January 2, 2014	Report No. 7	July 17, 2014	R-32-14	
October 1, 2014	Report No. 8	July 24, 2015	R-38-15	
December 7, 2015	BAL-001-2	April 21, 2016	R-14-16	
December 7, 2015	Report No. 9[2]	July 18, 2016	R-32-16A	
November 28, 2016	Report No. 10	July 26, 2017	R-39-17	
November 28, 2016	TPL-001-4	June 28, 2018	R-27-18A	
October 6, 2017	Report No. 11	October 1, 2018	R-33-18	
July 3, 2018	Report No.12	September 26, 2019	R-21-19	
August 12, 2019	Report No. 13	September 8, 2020	R-19-20	
October 8, 2020	Report No. 14			
October 8, 2020	Planning Coordinator			

British Columbia Utilities Commission (BCUC) Implementation Plan

Reliability Standard TPL-001-5.1
Transmission System Planning
Performance Requirements

Applicable Standard(s)

- TPL-001-5.1 – Transmission System Planning Performance Requirements

Requested Retirement(s)

- TPL-001-4 – Transmission System Planning Performance Requirements

Pre-requisite Standard(s)

- MOD-032-1 (as referenced from TPL-001-5.1 Requirement 1)

Applicable Entities

- Planning Coordinator
- Transmission Planner

General Considerations

The standard will become effective 36 months following the date that the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending BCUC approval. The 36-month period provides time for Planning Coordinators and Transmission Planners to develop, among other things:

- A procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- Coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional analysis required due to changes in the standard.

Following this 36-month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5.1 for Category P5 planning events involving single points of failure in Protection Systems.

Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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**" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation plan reflects consideration that Planning Coordinators and Transmission Planners will need time to conduct the new studies and analyses in order to coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5 (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5.1 Requirement R2, Part 2.7 for the non-redundant components of a Protection System identified in TPL-001-5.1 Table 1 Footnote 13.

Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in British Columbia.

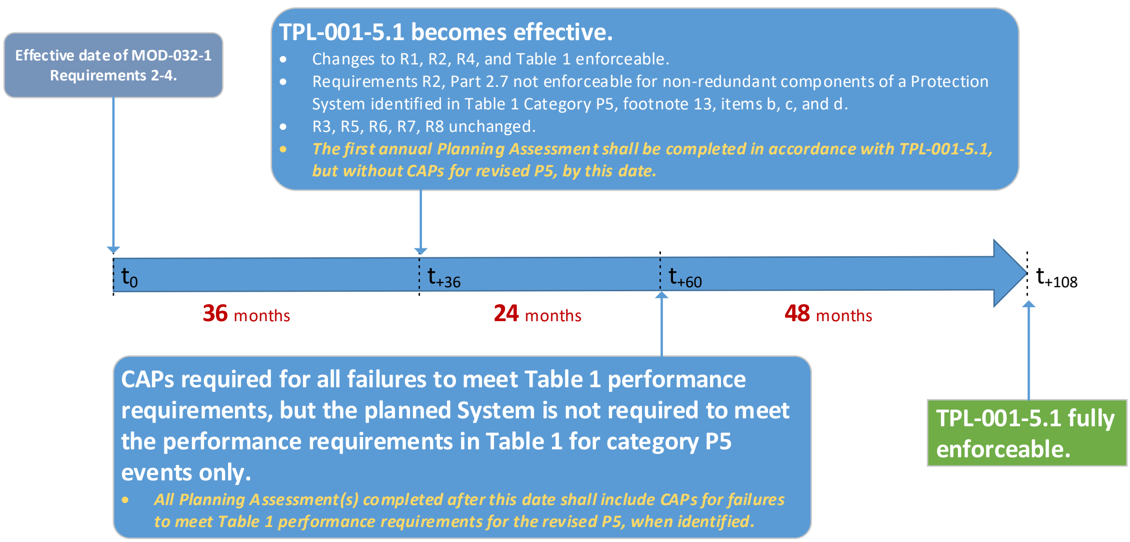


Figure 1 Implementation Plan Timeline

Effective Date

TPL-001-5.1 – Transmission System Planning Performance Requirements

The standard shall become effective on the first day of the first calendar quarter that is 36 months after the MOD-032-1 reliability standard become fully effective in British Columbia, pending the BCUC order(s) approving the TPL-001-5.1 and MOD-032-1 standards.

Compliance Date for TPL-001-5.1 Requirement 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items a, b, c, and d

Entities shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d until 24 months after the effective date of Reliability Standard TPL-001-5.1.

For CAPs developed to address failures to meet Table 1 performance requirements for the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5.1 with the bolded part of Requirement R2, Part 2.7 that states: "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.**"

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5.1 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) under Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items a, b, c, and d by 24 months after the effective date of the standard.

Retirement Date

TPL-001-4 – Transmission System Planning Performance Requirements

Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5.1 in British Columbia.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

~~Implementation Plan~~

~~Project 2015-10 Single Points of Failure Reliability Standard TPL-001-5.1 – Transmission System Planning Performance Requirements~~

~~Applicable Standard(s)~~

~~TPL-001-5.1 – Transmission System Planning Performance Requirements~~

~~Requested Retirement(s)~~

~~TPL-001-4 – Transmission System Planning Performance Requirements~~

~~Prerequisite Standard(s)~~

~~None~~

~~Applicable Entities~~

- ~~Planning Coordinator~~
- ~~Transmission Planner~~

British Columbia Utilities Commission (BCUC) Implementation Plan

Reliability Standard TPL-001-5.1
Transmission System Planning
Performance Requirements

Applicable Standard(s)

- TPL-001-5.1 – Transmission System Planning Performance Requirements

Requested Retirement(s)

- TPL-001-4 – Transmission System Planning Performance Requirements

Pre-requisite Standard(s)

MOD-032-1 (as referenced from TPL-001-5.1 Requirement 1)

Applicable Entities

- Planning Coordinator
- Transmission Planner

~~Background~~

~~Reliability Standard TPL-001-5.~~1 ~~revises the prior version of the TPL-001 standard in three key respects:~~

- ~~To address reliability issues concerning the study of single points of failure in Protection Systems, as identified in:~~
  - ~~Federal Energy Regulatory Commission (FERC) Order No. 754, issued on September 15, 2011; and~~
  - ~~the report dated September 2015 by two subcommittees under NERC Planning Committee , the System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee, titled~~ ~~*Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*~~
- ~~To address directives from FERC Order No. 786 (October 17, 2013) approving Reliability Standard TPL-001-4, relating to:~~
  - ~~modeling known outages with a duration of less than six months (paragraph 40); and~~
  - ~~adding stability analysis for the outage of major Transmission equipment with a lead time of one year or more (paragraph 89); and;~~
- ~~To replace references to the Reliability Standards MOD-010 and MOD-012, which have been superseded by MOD-032.~~

General Considerations

The standard will become effective 36 months following the date that the MOD-032-1 reliability standard becomes fully effective in British Columbia, pending ~~regulatory~~ BCUC approval. The 36-month period provides time for Planning Coordinators and Transmission Planners to develop, among other things:

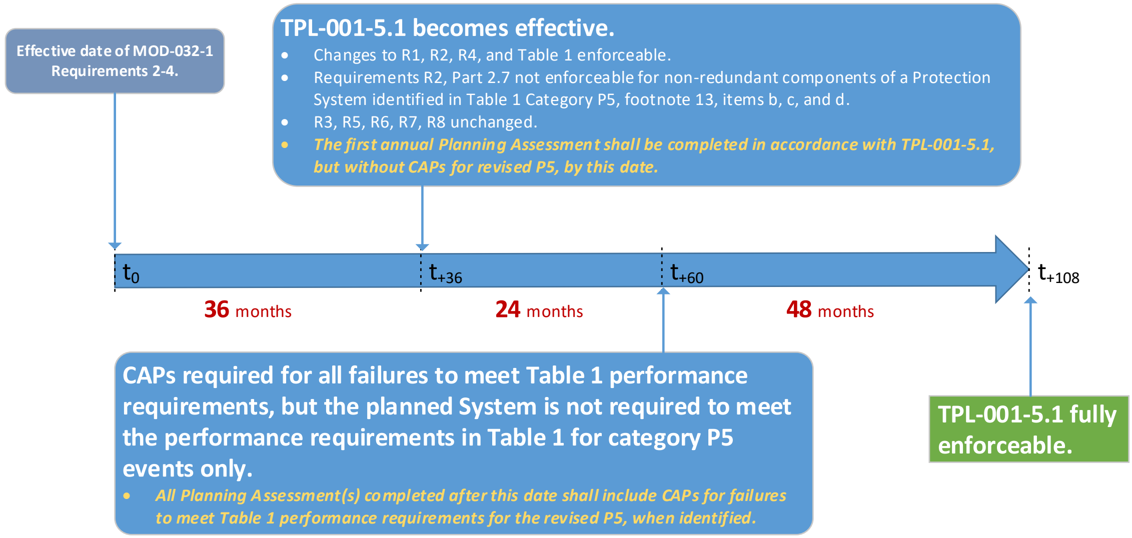
- A procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- Coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional analysis required due to changes in the standard.

Following this 36 month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5.1 for Category P5 planning events involving single points of failure in Protection Systems.

Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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**" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation plan reflects consideration that Planning Coordinators and Transmission Planners will need time to conduct the new studies and analyses in order to coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5 (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5.1 Requirement R2, Part 2.7 for the non-redundant components of a Protection System identified in TPL-001-5.1 Table 1 Footnote 13.

Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in British Columbia ~~in those jurisdictions where governmental approval is required~~.



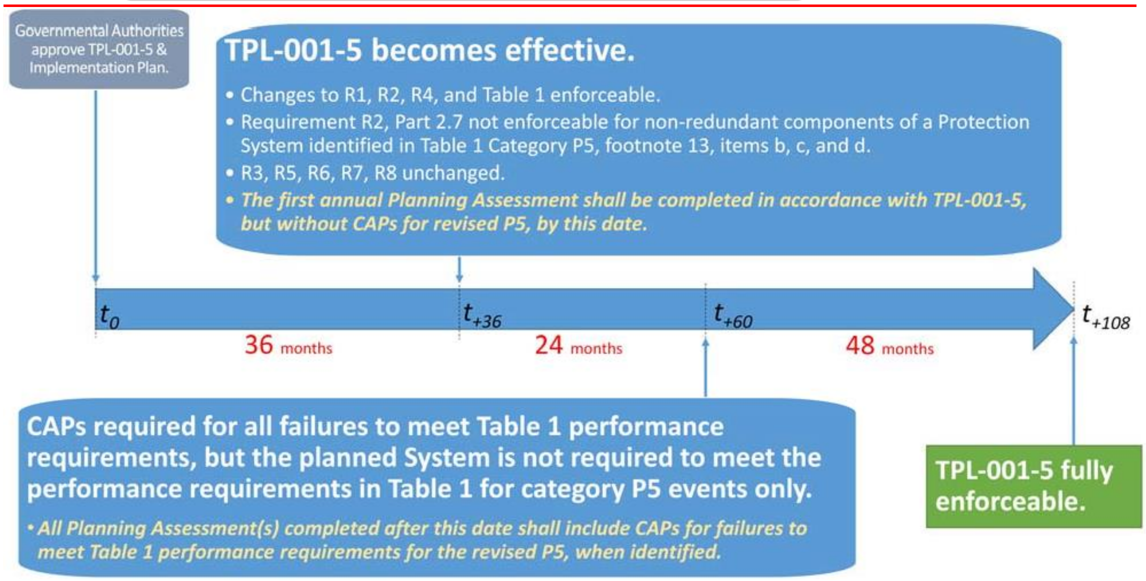


Figure 1 Implementation Plan Timeline

Effective Date

TPL-001-5.1 – Transmission System Planning Performance Requirements

~~Where approval by an applicable governmental authority is required, t~~The standard shall become effective on the first day of the first calendar quarter that is 36 months after the ~~effective date of the~~ MOD-032-1 reliability standard become fully effective in British Columbia, pending the ~~applicable governmental authority's~~BCUC order(s) approving the TPL-001-5.1 and MOD-032-1 ~~the~~ standards~~, or as otherwise provided by the applicable governmental authority~~.

~~Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.~~

Compliance Date for TPL-001-5.1 Requirement 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items a, b, c, and d

Entities shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d until 24 months after the effective date of Reliability Standard TPL-001-5.1.

For CAPs developed to address failures to meet Table 1 performance requirements for the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5.1 with the bolded part of Requirement R2, Part 2.7 that states: "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.**"

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Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5.1 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) under Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items a, b, c, and d by 24 months after the effective date of the standard.

Retirement Date

TPL-001-4 – Transmission System Planning Performance Requirements

Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5.1 in British Columbia.~~in the particular jurisdiction in which the revised standard is becoming effective.~~

British Columbia Utilities Commission (BCUC) Implementation Plan

Reliability Standard TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-4 is approved by the BCUC:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard*.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

Background

On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which was May 2018.

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. The Canadian Variance replaced, in its entirety, Requirement R7, Part 7.3 of the continent-wide standard for Canadian entities and added an alternate methodology for GMD Vulnerability Assessments, as described in Attachment 1-CAN. None of the continent-wide Requirements were changed. Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

The TPL-007-1 and TPL-007-3 reliability standards were considered for potential adoption in British Columbia (B.C.) via BCUC Assessment Report Nos. 10 and 13. The TPL-007-1 and TPL-007-3 reliability standards were each respectively held in abeyance under BCUC Order Nos. R-39-17 (July 26, 2017) and R-19-20 (September 8, 2020) due to unclear accountabilities pertaining to the Planning Coordinator functional role in B.C.

Effective Date

Compliance with TPL-007-4 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and/or validate new or modified studies, assessments, procedures, etc., to meet the TPL-007-4 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Reliability Standard TPL-007-4

The standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of the BCUC's order approving the standard.

Phased-In Compliance Dates

Compliance Date for TPL-007-4 Requirements R1 and R2

Entities shall be required to comply with Requirements R1 and R2 upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R3

Entities shall not be required to comply with Requirement R3 until the first day of the first calendar quarter, 18 months after the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R4, R5, R8, R9, R12, and R13

Entities shall not be required to comply with Requirements R4, R5, R8, R9, R12, and R13 until the first day of the first calendar quarter, 24 months after the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the first day of the first calendar quarter, 30 calendar months after the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R7 (Parts 7.1, 7.2), Requirement R11 (Parts 11.1, R11.2), and Regional Variances for Canadian Jurisdictions D.A.7.3, D.A.7.4, D.A.7.5, D.A.11.3, D.A.11.4, and D.A.11.5
Entities shall not be required to comply with Requirement R7 (Parts 7.1, 7.2), Requirement R11 (Parts 11.1, R11.2), and Regional Variances for Canadian Jurisdictions D.A.7.3, D.A.7.4, D.A.7.5, D.A.11.3, D.A.11.4, and D.A.11.5, until the first day of the first calendar quarter, 54 months after the effective date of Reliability Standard TPL-007-4.

Initial Performance of Periodic Requirements

Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.

British Columbia Utilities Commission (BCUC)

Implementation Plan

~~Project 2019-01 Modifications to TPL-007-3~~

Reliability Standard TPL-007-4 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Applicable Standard

- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

~~Requested Retirement~~

- ~~TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events~~

Prerequisite Standard

None

Revisions to Glossary Terms

There is one new definition in the proposed standard, which shall become effective when TPL-007-4 is approved by the BCUC:

> **Geomagnetic Disturbance Vulnerability Assessment or GMD Vulnerability Assessment:** *Documented evaluation of potential susceptibility to voltage collapse, Cascading, or localized damage of equipment due to geomagnetic disturbances.*

Applicable Entities

- *Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;*
- *Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and*
- *Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard.*

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high-side, wye-grounded winding with terminal voltage greater than 200 kV.

~~Terms in the NERC Glossary of Terms~~

~~There are no new, modified, or retired terms.~~

Background

On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which was May 2018.

On November 15, 2018, the Federal Energy Regulatory Commission (FERC) issued Order No. 851 approving Reliability Standard TPL-007-2 and its associated implementation plan. In the order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 12 months from the effective date of Reliability Standard TPL-007-2 to submit a revised standard (July 1, 2020).

On February 7, 2019, the NERC Board of Trustees adopted Reliability Standard TPL-007-3, which added a Variance option for applicable entities in Canadian jurisdictions. The Canadian Variance replaced, in its entirety, Requirement R7, Part 7.3 of the continent-wide standard for Canadian entities and added an alternate methodology for GMD Vulnerability Assessments, as described in Attachment 1-CAN. None of the continent-wide Requirements were changed. ~~No continent-wide requirements were changed.~~ Under the terms of its implementation plan, Reliability Standard TPL-007-3 became effective in the United States on July 1, 2019. All phased-in compliance dates from the TPL-007-2 implementation plan were carried forward unchanged in the TPL-007-3 implementation plan.

The TPL-007-1 and TPL-007-3 reliability standards were considered for potential adoption in British Columbia (B.C.) via BCUC Assessment Report Nos. 10 and 13. The TPL-007-1 and TPL-007-3 reliability standards were each respectively held in abeyance under BCUC Order Nos. R-39-17 (July 26, 2017) and R-19-20 (September 8, 2020) due to unclear accountabilities pertaining to the Planning Coordinator functional role in B.C.

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~~General Considerations~~

~~This implementation plan is intended to integrate the new and revised requirements in TPL-007-4 in the existing timeframe under the TPL-007-3 implementation plan.~~

Effective Date

~~The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. These phased-in compliance dates represent the dates that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.~~

Compliance with TPL-007-4 shall be implemented over a 5-year period as follows. Phased implementation provides:

- Necessary time for entities to develop the required models.
- Proper sequencing of assessments. The assessment of thermal impact on transformers is dependent upon geomagnetically-induced current (GIC) flow calculations that are determined by the responsible planning entity.
- Necessary time for development of viable Corrective Action Plans, which may require entities to develop, perform, and/or validate new or modified studies, assessments, procedures, etc., to meet the TPL-007-4 requirements. Some mitigation measures may have significant budget, siting, or construction planning requirements.

Reliability Standard TPL-007-4

~~Where approval by an applicable governmental authority is required, t~~The standard shall become effective on the first day of the first calendar quarter that is six (6) months after the effective date of ~~the applicable governmental authority's~~the BCUC's order approving the standard~~, or as otherwise provided for by the applicable governmental authority.~~.

~~Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is six (6) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.~~

Phased-In Compliance Dates

Compliance Date for TPL-007-4 Requirements R1 and~~,~~ R2~~, R5, and R9~~

Entities shall be required to comply with Requirements R1 and~~,~~ R2~~, R 5, and R9~~ upon the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirement R3

Entities shall not be required to comply with Requirement R3 until the first day of the first calendar quarter, 18 months after the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R4, R5, R8, R9, R12, and R13

Entities shall not be required to comply with Requirements R4, R5, R8, R9, R12, and R13 until the ~~later of:~~

~~(i) July 1, 2021; or (ii)~~first day of the first calendar quarter, 24 months after the effective date of Reliability Standard TPL-007-4.

Compliance Date for TPL-007-4 Requirements R6 and R10

Entities shall not be required to comply with Requirements R6 and R10 until the ~~later of: (i) January 1, 2022; or (ii)~~first day of the first calendar quarter, 30 calendar months after the effective date of Reliability Standard TPL-007-4.

~~**Compliance Date for TPL-007-4 Requirements R3, R4, and R8**~~

~~Entities shall not be required to comply with Requirements R3, R4, and R8 until the later of: (i) January 1, 2023; or (ii) the effective date of Reliability Standard TPL-007-4.~~

Compliance Date for TPL-007-4 Requirement R7 (Parts 7.1, 7.2), Requirement R11 (Parts 11.1, R11.2), and Regional Variances for Canadian Jurisdictions D.A.7.3, D.A.7.4, D.A.7.5, D.A.11.3, D.A.11.4, and D.A.11.5

Entities shall not be required to comply with Requirement R7 (Parts 7.1, 7.2), Requirement R11 (Parts 11.1, R11.2), and Regional Variances for Canadian Jurisdictions D.A.7.3, D.A.7.4, D.A.7.5, D.A.11.3, D.A.11.4, and D.A.11.5, ~~Requirement R7~~ until the ~~later of: (i) January 1, 2024; or (ii)~~first day of the first calendar quarter, 54 months after the effective date of Reliability Standard TPL-007-4.

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~~Compliance Date for TPL-007-4 Requirement R11~~
~~Entities shall not be required to comply with Requirement R11 until the later of: (i) January 1, 2024; or (ii) six (6) months after the effective date of Reliability Standard TPL-007-4.~~

~~Retirement Date~~

~~Standard TPL-007-3~~
~~Reliability Standard TPL-007-3 shall be retired immediately prior to the effective date of TPL-007-4 in the particular jurisdiction in which the revised standard is becoming effective.~~

Initial Performance of Periodic Requirements
Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically-induced current (GIC) flow information specified in Requirement R5, Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9, Part 9.1 is received.