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May 1, 2019

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)
Assessment Report No. 12 (Report)**

BC Hydro writes to the BCUC to provide its Report dated May 1, 2019 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 13 new and revised/replacement reliability standards (**Revised Standards**) and retiring two reliability standards (**Retired Standards**) for the bulk electric system in B.C. In the Report, BC Hydro recommends that the 13 Revised Standards are suitable for adoption in B.C., and the two Retired Standards are suitable for retirement in B.C.

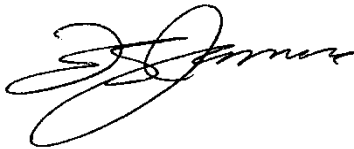
BC Hydro has also assessed and made a recommendation regarding adoption of the North American Electric Reliability Corporation Glossary of Terms dated July 3, 2018 (**NERC Glossary**) in the Report. The NERC Glossary contains five new or revised defined terms (**Revised Terms**). In the Report, BC Hydro recommends that all five Revised Terms are suitable for adoption in B.C. The NERC Glossary should therefore be adopted as outlined more specifically in the Report.

BC Hydro has included a proposed process for the BCUC's adoption of the Revised Standards and Revised Terms, in section 3.2 of the Report.

May 1, 2019
Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Mandatory Reliability Standards (MRS)
Assessment Report No. 12 (Report)

For further information, please contact Geoff Higgins at 604-623-4121 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,



Fred James
Chief Regulatory Officer

st/ma

Enclosure (1)

Copy to: B.C. MRS Program Registered Entities.

Mandatory Reliability Standards Assessment Report No. 12

May 2019

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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**) Assessment Report No. 12 (**Report**), pertaining to the Bulk Electric System (**BES**) in British Columbia (**B.C.**), to the British Columbia Utilities Commission (**BCUC or Commission**) for consideration regarding the reliability impacts, suitability, potential costs and reliability standard applicability of adopting 13 (two new and 11 revised) reliability standards (**Revised Standards**) and retiring two reliability standards (**Retired Standards**), as well as adopting five (one new and four revised) defined terms (**Revised Terms**) from the North American Electric Reliability Corporation (**NERC**) Glossary of Terms (**NERC Glossary**) dated July 3, 2018.

1.2 Contents of the Report

The Report is organized as follows:

Section [2](#) outlines special considerations BC Hydro raises for the BCUC's consideration.

Section [3](#) summarizes the Report findings, provides an outline of the Draft Order and recommends a proposed assessment process.

Section [4](#) explains BC Hydro's assessment process, including its consultation with stakeholders.

Section [5](#) summarizes BC Hydro's approach to assessing the Revised Standards and Retired Standard, and provides the results of that assessment.

Section [6](#) summarizes the results of the assessment of the Revised Terms using the approach as described in section [5](#).

Section [7](#) provides BC Hydro's conclusions.

2 Special Considerations

BC Hydro raises the following special considerations for this report:

2.1 Reliability Standards with Reliability Related Requirements for Planning Authority (PA)/Planning Coordinator (PC)

There are no Revised Standards with dependencies on the PA/PC function in scope of this report.

In the Reasons for Decision for Order No. R-41-13 (Appendix A, page 20), the BCUC found that the issue in relation to the extent of the PA/PC operations/footprint in B.C. was beyond the scope of the MRS Assessment Report No. 6 review process. The BCUC Order Nos. R-32-14, R-38-15, R-32-16, R-39-17, and R-33-18 addressing the reliability standards in MRS Assessment Report Nos. 7, 8, 9, 10, and 11 were consistent with this approach for reliability standards that reference the PC function.

Concurrent with this filing BC Hydro is submitting a letter to the BCUC in May 2019 setting out a proposed process to expand its registered PA/PC function beyond its own asset footprint.

2.2 Reliability Standards with Reliability Related Requirements for Reliability Coordinator (RC)

As of December 31, 2019, Peak Reliability, the currently designated RC in the Western Electricity Coordinating Council (**WECC**) region (inclusive of B.C.) will no longer provide RC services.

In connection with the wind-up of Peak Reliability, BC Hydro submitted its application on September 4, 2018 to WECC¹ to become registered for the RC function by September 2019. Subsequently, BC Hydro submitted a filing with the BCUC on October 29, 2018 to support its application to register for the RC function in B.C.

¹ WECC is the BCUC's MRS administrator assisting with registration and the monitoring of compliance with the reliability standards in B.C.

1 Accordingly, the BC Hydro RC department has assessed and provided associated
2 estimated costs on those requirements within the Revised Standards specifically
3 related to the RC function.

4 **2.3 B.C. CIP-003-7 Implementation Plan**

5 BC Hydro recommends that in connection with the recommendation to adopt the
6 CIP-003-7 Revised Standard, a B.C.-specific version of the Federal Energy Regulatory
7 Commission (**FERC**) approved related Implementation Plan² be incorporated into the
8 B.C. MRS program pursuant to an order of the BCUC providing for the administration of
9 adopted reliability standards. BC Hydro has drafted a B.C.-specific version of the
10 CIP-003-7 Implementation Plan to align it with the B.C. MRS program. The B.C.
11 CIP-003-7 Implementation Plan is based on a combination of the CIP-003-7 and
12 CIP-003-6 implementation plans developed by NERC, and both a clean and redline draft
13 showing the changes proposed for the B.C.-specific version in relation to the NERC
14 CIP-003-7 implementation plan are included in Attachment D-1 to Appendix D for the
15 BCUC's review.

16 The B.C. CIP-003-7 Implementation Plan provides clarity to entities on implementation
17 times for initial compliance with a subset of requirements pertinent to low impact BES
18 Cyber Systems in regards to electronic and physical security policies and plans, security
19 awareness and cyber security incident response plans, CIP Exceptional Circumstance
20 policies, as well as associated Transient Cyber Asset and Removable Media security
21 plans in comparison with the CIP-003-5 reliability standard which will be superseded. It
22 is BC Hydro's opinion that adopting the B.C.-specific CIP-003-7 Implementation Plan will
23 not adversely impact the reliability of the BES and would allow a similar level of flexibility
24 to B.C registered entities that U.S. based registered entities are afforded during its
25 implementation.

² FERC Docket No.RM17-11-000; Order No. 843.

1 Therefore, in connection with the recommendation to adopt CIP-003-7, BC Hydro
2 recommends that a B.C.-specific version of the CIP-003-7 Implementation Plan be
3 incorporated into the B.C. MRS program pursuant to an order of the BCUC providing
4 for the administration of adopted reliability standards.

5 As background to B.C.'s transition from CIP-003-5 to CIP-003-7, in MRS Assessment
6 Report No. 10, BC Hydro recommended that CIP-003-6 and two new NERC Glossary
7 Terms (Low Impact BES Cyber System Electronic Access Point (**LEAP**) and Low Impact
8 External Routable Connectivity (**LERC**)) intended for CIP-003-6 be held in abeyance and
9 be of no force or effect in B.C. due to technical suitability issues that would not improve
10 reliability and instead place undue burden on responsible entities. BCUC
11 Order No. R-39-17 held CIP-003-6 and the two new NERC Glossary Terms in abeyance.

12 **2.4 B.C. PRC-025-2 Implementation Plan**

13 BC Hydro recommends that in connection with the recommendation to adopt
14 PRC-025-2, a B.C.-specific version of the FERC-approved PRC-025-2 Implementation
15 Plan³ be adopted in B.C. BC Hydro has drafted a B.C.-specific version of the PRC-025-2
16 Implementation Plan to align it with the B.C. MRS program. The B.C. PRC-025-2
17 Implementation Plan is based on the equivalent implementation plan developed by
18 NERC, and both a clean and redline draft showing the changes proposed for the
19 B.C.-specific version are included in Attachment D-2 to Appendix D of the Report for the
20 BCUC's review. The B.C. PRC-025-2 Implementation Plan provides clarity on the
21 implementation timeframes for initial compliance in regards to new load-responsive
22 protective relay loadability options specific to dispersed power producing resources and
23 changes to PRC-025-1 options for load-responsive protective relay loadability settings
24 that may cause an entity to re-evaluate their settings, whilst taking into consideration
25 generator outage cycles. It is BC Hydro's opinion that adopting the B.C.-specific
26 PRC-025-2 Implementation Plan will not adversely impact the reliability of the BES and

³ FERC Docket No. RD18-4-000.

would allow the same level of flexibility to B.C. registered entities that U.S. based registered entities are afforded during its implementation.

Therefore, in connection with the recommendation to adopt PRC-025-2 BC Hydro recommends that a B.C.-specific version of the PRC-025-2 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 Report Summary

BC Hydro is recommending the adoption of all 13 Revised Standards, all five Revised Terms, as well as the retirement of the two Retired Standards, all of which were assessed in the Report. The 13 Revised Standards being recommended for adoption in B.C. would entirely supersede 13⁴ reliability standards adopted in B.C. by Order Nos. R-1-13, R-41-13, R-32-14, R-38-15, R-32-16A, R-39-17, and R-33-18.

BC Hydro has concluded that the Revised Standards and Revised Terms being recommended for adoption 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 assessed its estimated incremental one-time and ongoing annual costs of achieving and maintaining compliance with the adoption of the Revised Standards and Revised Terms as mandatory in B.C. BC Hydro's responses are reproduced in full in Appendix C-1 of the Report. Consistent with the approach taken in previous MRS assessment reports, BC Hydro has also sought input from B.C. MRS registered entities regarding their estimated incremental one-time and annual ongoing costs associated with achieving and maintaining compliance with the Revised Standards and with using the Revised Terms.

⁴ Refer to Appendix A-1 for a list of BCUC approved reliability standards that would be superseded by reliability standards assessed in the Report.

A complete list of the registered entities with whom BC Hydro consulted is provided in [Table 1](#), section [4.2](#). A detailed breakdown of the estimated incremental one-time and ongoing costs reported by BC Hydro and the registered entities is provided in [Table 3](#), section [5.3](#) and [Table 5](#), section [6.4](#). Registered entities' responses are reproduced in full in Appendix C-3.

On the basis of BC Hydro's own assessment and the responses received from those registered entities providing cost estimates, the cumulative cost for B.C. registered entities to achieve and maintain compliance with the 13 Revised Standards and five Revised Terms being recommended for adoption in B.C. is estimated to be a minimum of \$27,051,500 with respect to one-time costs, and a minimum of \$6,155,833 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: implementation of electronic and physical protections for low impact BES Cyber Systems as well as for associated Transient Cyber Assets and Removable Media; implementation of new intra and inter entity protection system settings and coordination requirements; and implementation of new generator relay loadability setting criteria. The remaining costs are largely associated with reviews and revisions of procedure documentation and training.

3.1 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 Revised Standards, the BCUC approved reliability standards to be superseded by the Revised Standards, and the Retired Standards. Attachment A also lists the Revised Terms to be adopted in B.C. and the BCUC approved NERC Glossary to be superseded by the Revised Terms. 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 of the reliability standards that would be in force in B.C., including those assessed in the Report, and those reliability standards held in abeyance. The table also provides the BCUC Order under which each of the reliability standards was adopted and the effective date was set;
- Attachment C - For ease of reference, BC Hydro is including Table 1 in Attachment C which lists all of the B.C.-specific exceptions to the NERC Glossary, starting from MRS Assessment Report No. 6;⁵ and
- Attachment D – Includes B.C.-specific versions of the CIP-003-7 Implementation Plan and PRC-025-2 Implementation Plan to be implemented in B.C. as discussed in detail in sections [2.3](#) and [2.4](#) respectively.

3.2 Proposed Process

This is the twelfth annual MRS assessment report to be submitted to the BCUC. 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](#).

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

⁵ Refer to Table 2 in 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.

process, the BCUC would determine whether the Revised Standards and Revised Terms should be adopted in B.C. and whether the Retired Standards should be retired.

4 Standards Assessment Process used in the Report

4.1 Identification of Standards for Review and Inclusion in the Report

For this report, BC Hydro has assessed reliability standards that were FERC approved with an effective Order within the period between, and including, December 1, 2017 and November 30, 2018 (the **2018 Assessment Period**).

A November 30, 2018 cut-off date is required to allow time for BC Hydro to assess the reliability standards identified in the 2018 Assessment Period and consult with registered entities regarding any impacts to them in achieving compliance with those reliability standards. For efficiency, rather than submitting a separate assessment report for each reliability standard, BC Hydro batches reliability standards and files one assessment report with the BCUC each year. This same approach has been used in previous MRS assessment reports.

On October 5, 2018, BC Hydro requested from the BCUC an extension to allow certain MRS to be included in the Report and to be assessed over a period of greater than a year. This extension request was approved pursuant to BCUC Order No. R-36-18.

Should BC Hydro or the BCUC determine that a particular reliability standard is sufficiently critical to reliability that it warrants immediate implementation, BC Hydro would file a reliability standard-specific assessment report and not wait until its next 'batch' assessment report. There are no such reliability standards that have been identified within the 2018 Assessment Period.

In this report, BC Hydro is assessing the 13 Revised Standards and two Retired Standards identified in [Table 2](#). Each of the Revised Standards is either new or a revision to a previously adopted reliability standard(s) in B.C. A list of all of the Revised

Standards and Retired Standards is also 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 Revised Standards.

4.2 Consultation

BC Hydro consulted with the B.C. MRS registered entities listed below in [Table 1](#).

Table 1 B.C. MRS Program Registered Entity List

Registered Entities	Registered Entities (Continued)
Bear Mountain Wind Limited Partnership (BMWL)	Intercontinental Pulp Mill (IPML)
British Columbia Hydro and Power Authority (BCHA)	Jimmie Creek Limited Partnership (JCLP)
Cape Scott Wind LP (CSCO)	Lehigh Cement (LHC)
Capital Power Limited Partnership (CPLP)	Meikle Wind Energy Limited Partnership (MWEL)
Cariboo Pulp & Paper Company (CPPC)	Northwood Pulp Mill (NPM)
Catalyst Paper - Crofton Division (CPCD)	Prince George Pulp & Paper Mill (PGPP)
Catalyst Paper - Port Alberni Division (CPPAD)	Quesnel River Pulp and Paper (QUES)
Catalyst Paper - Powell River Division (CPPR)	Rio Tinto Alcan (RTA)
Coast Mountain Hydro Limited Partnership (CMHL)	Teck Metals Ltd (TECK)
Conifex Power Limited Partnership (CONP)	Toba Montrose General Partnership (TMGP)
Dokie General Partnership (DGP)	Tolko Industries Limited (TIL)
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)	

Each registered entity on the list was issued an email package on December 15, 2018 advising that 12 Revised Standards (refer to details below regarding the additional Revised Standard later identified and included for assessment), two Retired Standards, and five Revised Terms would be assessed in the Report. With the exception of Conifex Power Limited Partnership which became registered under the B.C. MRS program on February 14, 2019 and received the package on February 19, 2019.

The email packages contained instructions and a link to the BC Hydro Reliability Compliance internet website where two survey forms (one for Revised Standards and Retired Standards and another for Revised Terms) were provided for completion by entities (refer to Appendix C). Entities were asked to complete and return the survey forms to BC Hydro by end of day February 28, 2019. On January 11, 2019, BC Hydro held an informational session via teleconference for all registered entities in B.C. A reminder notice to complete the survey forms was sent to each registered entity on February 6, 2019.

On February 26, 2019, BC Hydro noted that NERC's website (the resource BC Hydro relies upon for its Report scope identification) had been updated to include a 13th Revised Standard (PER-003-2) which had been adopted by FERC within the Assessment Period. BC Hydro emailed all registered entities on February 27, 2019 regarding the inclusion of PER-003-2 for assessment in the Report and noted that it only applied to registered RCs, Transmission Operators (**TOP**), and Balancing Authorities (**BA**). BC Hydro granted an extension for feedback to only those applicable registered entities in relation to PER-003-2 (BC Hydro, Fortis BC, and Teck Metals) to March 14, 2019. This same email included a second reminder to all other registered entities to complete the survey forms by end of day February 28, 2019.

The entities were asked to provide information for each Revised Standard, Retired Standard and Revised 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 in order 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.

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

Including BC Hydro, a total of 29 registered entities were contacted. The six entities who responded were:

BC Hydro, Fortis BC, Northwood Pulp Mill, Catalyst Paper – Crofton, Port Alberni, and Powell River. Catalyst Paper Corporation's Crofton, Port Alberni, and Powell River Divisions provided a single consolidated survey response. BC Hydro's responses are attached in full in Appendix C-1 and registered entities' responses are attached in full in Appendix C-3.

5 Assessment of Individual Standards

As noted previously, the 13 Revised Standards and two Retired Standards assessed in the Report are listed in Table 1 in Appendix A-1. Clean and red-lined copies of the Revised Standards are listed in Appendix A-2.

BC Hydro has assessed the 13 Revised Standards and two Retired Standards against the criteria stipulated by legislation in B.C. (section 125.2(3) of the UCA).

- Section [5.1](#) summarizes BC Hydro's approach to addressing these criteria;
- Section [5.2](#) provides a description of each Revised Standard and Retired Standard and an explanation of the reliability and suitability and applicability issues along with BC Hydro's conclusions; and
- Section [5.3](#) addresses the cost assessment and summarizes BC Hydro's final assessment of all of the Revised Standards and Retired Standards.

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

The analytical approach taken to evaluate reliability standards identified in the Report against the legislated assessment criteria has not changed from that used in previous 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 Revised Standard included in Appendix A-2. Nevertheless, BC Hydro recognizes that the compliance-related provisions may be adopted by the BCUC.

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

5 **5.1.1 Analytical Approach in Assessing Adverse Reliability Impacts**

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

16 **5.1.2 Analytical Approach for the Suitability Assessment**

17 The Report uses the same criteria to assess the Revised Standards and Retired
18 Standards that were developed for the previous MRS assessment reports. The
19 two criteria used for this analysis are set out below:

- 20 (a) "Administrative Suitability" means that the requirements in the reliability standard
21 are fit and appropriate for implementation in light of the policy and regulatory
22 framework in B.C. The requirements can be implemented without requiring the
23 ongoing involvement of NERC, the U.S. Government, or other extra-jurisdictional
24 entities in such a manner as would impair the operation and enforcement of the
25 requirement in B.C. If one or more of the requirements in the reliability standard
26 incorporate by reference reliability standards not yet adopted in other jurisdictions,

1 the remaining requirements in the reliability standard can still be implemented
2 presently in B.C. without giving effect to the particular requirement(s) containing the
3 cross reference; and

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

8 **5.1.3 Analytical Approach for the Cost Assessment**

9 BC Hydro’s approach to assess the potential costs of the Revised Standards in the
10 Report is consistent with the approach used to assess reliability standards in previous
11 MRS assessment reports. The objective is to provide an estimate of the costs of
12 adopting reliability standards in B.C. sufficient to inform the BCUC’s public interest
13 assessment. Accordingly, only the costs that B.C. entities will potentially incur in order to
14 achieve and maintain full compliance with the Revised Standards were assessed. Any
15 costs associated with B.C. entities attaining or maintaining compliance with pre-existing
16 reliability standards in B.C. were excluded.

17 **5.1.4 Analytical Approach for the Application of the Reliability Standards**

18 Pursuant to the obligations contained in paragraph 125.2(3)(c.1) of the UCA, BC Hydro’s
19 approach to assess the application of the Revised Standards and Retired Standards to
20 persons or persons in respect of specified equipment in the Report is consistent with the
21 approach used to review reliability standards in previous MRS assessment reports.

22 BC Hydro assesses the Applicability section contained in the Introduction of the Revised
23 Standard and Retired Standards at Section A.4, to ensure consistency with the
24 functional registration categories contained in the B.C. MRS program, as contained in
25 the MRS Rules of Procedure in B.C. BC Hydro considers this approach to satisfy the
26 obligations 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.

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

In terms of the assessment of the Revised Standards and Retired Standards against the reliability and suitability criteria, BC Hydro first performed an initial screening against the criteria described in section [5.1](#) 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 Revised Standards for potential issues regarding adverse reliability impacts and suitability are summarized below in [Table 2](#), which includes:

- The "Standard" column, which identifies the Revised Standards and Retired Standards assessed;
- The "Changed from BCUC Approved Standard" column, which identifies whether the Revised 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 in order 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

1 information to NERC or WECC (i.e., lack of clarity on reporting instructions,
2 references to undefined processes or reporting tools, etc.);

3 ► Refers to Standard not yet FERC Approved: Identifies a potential Technical or
4 Administrative Suitability issue with a Revised Standard as it contains one or
5 more references to other reliability standards that have not yet been approved
6 by FERC in the U.S., and thereby not assessed for adoption in B.C., which
7 would affect the ability to implement one or more requirements of
8 the Revised Standard; and

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

Table 2 Initial Screening of Revised Standards and Retired Standards for Adverse Reliability Impact and Suitability

No.	Standard	Changed from BCUC Approved Standard	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	BAL-002-3	Yes	No	No	No	No	No	No
2	BAL-004-0	Retired	No	Yes ¹	No	No	No	No
3	BAL-004-WECC-3	Yes	No	No	No	No	No	No
4	CIP-003-7	Yes	No	No	No	No	No	No
5	EOP-004-4	Yes	No	No	Yes ²	Yes ³	No	No
6	EOP-005-3	Yes	No	No	No	No	No	No
7	EOP-006-3	Yes	No	No	No	No	No	No
8	EOP-008-2	Yes	No	No	No	Yes ³	No	No
9	FAC-501-WECC-2	Yes	No	No	No	No	No	No
10	PER-003-2	Yes	No	No	No	No	No	No
11	PER-006-1	New	No	No	No	No	No	No
12	PRC-025-2	Yes	No	No	No	No	No	No
13	PRC-027-1	New	No	No	No	No	No	No
14	VAR-001-5	Yes	No	No	No	No	No	No
15	VAR-002-WECC-2	Retired	No	No	No	No	No	No

1. Retired Standard BAL-004-0 Requirements 1 and 4 are applicable to RCs only. Requirement 1 requires appointment by the NERC Operating Committee to identify a single RC per Interconnection (for B.C., the Western Interconnection) to serve as the Interconnection Time Monitor and Requirement 4 authorizes RCs to make requests of the identified Interconnection Time Monitor to terminate a Time Error Correction due to reliability considerations. As this standard is being retired, there are no perceived suitability issues given that this requirement currently only applies to Peak Reliability as the RC for B.C. and the Western Interconnection.
2. Revised Standard EOP-004-4 Requirement 1 requires entities to report events to the Electric Reliability Organization (ERO). In the U.S. the ERO is NERC; however, there is no ERO in B.C. Entities subject to MRS are not required to report to NERC, because B.C. is outside of NERC's jurisdiction; however, entities may report to NERC on a voluntary basis. There are no perceived suitability issues that would impact a B.C. entity's ability to comply with the identified Revised Standard requirements. Similar ERO event reporting requirements exist within the BCUC adopted and effective EOP-004-3 reliability standard Requirement 1 for which entities have not been required to report events to NERC.
3. Revised Standard EOP-004-4 Requirements 1 and 2 and EOP-008-2 Requirement 8 require entities to report events and provide plans respectively, to WECC as their "Regional Entity". WECC is the BCUC's designated compliance administrator in B.C., so there are no perceived suitability issues that would impact a B.C. entity's ability to comply with the identified Revised Standard requirements.

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

BC Hydro's final assessment, based on internal and external responses from B.C. registered entities, is summarized below in [Table 3](#), which includes:

- BC Hydro's final assessment as to whether the adoption of the Revised Standards or retirement of Retired Standards will give rise to adverse reliability consequences;⁶
- BC Hydro's final assessment as to the suitability of the Revised Standards, based on the criteria described in section [5.1.2](#);
- BC Hydro's and registered entities' 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 Revised 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 Revised Standards is included as a separate paragraph at the end of section [5.3](#).

⁶ No adverse reliability consequences were identified during the final assessment.

1
2

**Table 3 Final Assessment Summary of Revised
Standards and Retired Standards**

Standard	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
BAL-002-3	None reported.	BC Hydro RC - R1: \$2,000; coordinate with Northwest Power Pool (NWPP) Reserve Sharing Group (RSG), BC Hydro's BA function, and other RCs to develop communicating protocols and revise procedures. BC Hydro - R1: \$2,000; coordinate with NWPP RSG, BC Hydro's RC function, and other RCs to develop communicating protocols and revise procedures.	None reported.	First day of the first calendar quarter, six months after BCUC adoption.
BAL-004-0	Yes ¹	None reported.	None reported.	Retire immediately after BCUC approval.
BAL-004-WECC-3	None reported.	BC Hydro - R1: \$1,000; minor revisions to Operating Orders and minor updates to training materials for System Operators required.	None reported.	First day of the second calendar quarter after BCUC adoption.

Standard	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
CIP-003-7	None reported.	BC Hydro - R1, R2: \$25,030,000; 115 transmission stations and 18 generation stations classified as low impact for which incremental electronic and physical security protections will need to be afforded to associated BES Cyber Systems per the policy and plan requirements of CIP-003-7 (per Attachment 1 Sections 2, 3, and 5) and expansion of Transient Cyber Asset and Removable Media protections to low impact BES Cyber Systems. Costs are also inclusive of actions regarding identifying applicable inventories, policy, plan, and procedure development/revisions, and initial training efforts. Catalyst Paper (Crofton, Port Alberni, Powell River) – R1, R2: \$50,000; significant revision of cyber policies required. New requirements for testing and verification triggered by mandatory participation in BC Hydro's Remedial Action Scheme and Special Protection System. May require installation of new hardware and software. FortisBC – \$250,000 – \$475,000; device and configuration changes are required at low impact BES Cyber Systems as well as identification of BES Cyber Assets and creation of associated documentation.	BC Hydro - R1, R2: \$5,862,000; reviews/updates to policies, plans, procedures, drawings, and associated training reinforcement. Maintenance of electronic and physical access controls and ongoing inventory management. Catalyst Paper (Crofton, Port Alberni, Powell River) – R1, R2: \$20,000. FortisBC – \$30,000 – \$60,000.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter after BCUC adoption. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C.-specific version of the CIP-003-7. Implementation Plan be implemented in B.C pursuant to an order of the BCUC providing for the administration of adopted reliability standards. Please refer to section 2.3 of the Report. Feedback Exceptions: Catalyst Paper (Crofton, Port Alberni, Powell River) – One year after BCUC adoption. FortisBC – 24-36 months after BCUC adoption.
EOP-004-4	Yes ²	BC Hydro RC – R1, R2: \$1,000; minor updates to RC function documentation after consulting with other registered Transmission Owner (TO)/TOP/Generation Owner (GO)/Generation Operator (GOP) entities, consulting with BC Hydro's joint event reporting plan for its BA/TO/TOP/GO/GOP functions, and to distribute final versions of RC event reporting plan.	BC Hydro RC – R1, R2: \$500; perform annual reviews of RC function event reporting plan.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter, 12 months after BCUC adoption. Feedback Exceptions: FortisBC - Immediately after BCUC approval. (This analysis is contingent that new event reporting processes to be implemented by the BC Hydro RC will not be significantly different than the current Peak RC processes.)

Standard	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
EOP-005-3	None reported.	None reported.	None reported.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter, 12 months after BCUC adoption. Feedback Exceptions: FortisBC - Immediately after BCUC approval. (This analysis is contingent that new system restoration processes, reviews, and training drills to be implemented by the BC Hydro RC will not be significantly different than the current Peak RC processes.)
EOP-006-3	None reported.	BC Hydro RC – R4-R6: \$500; edits to other RC restoration plans between annual reviews and the 60 day submission requirement.	BC Hydro RC – R4-R6: \$500; edits to other RC restoration plans between annual reviews and the 60 day submission requirement.	First day of the first calendar quarter, 12 months after BCUC adoption.
EOP-008-2	Yes ³	None reported.	None reported.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter, 12 months after BCUC adoption. Feedback Exceptions: FortisBC – R1, R2, R4-R8: Immediately after BCUC approval.
FAC-501-WECC-2	None reported.	None reported.	None reported.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter after BCUC adoption. Feedback Exceptions: FortisBC – Immediately after BCUC approval.
PER-003-2	None reported.	None reported.	None reported.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter, six months after BCUC adoption. Feedback Exceptions: FortisBC – R2: Immediately after BCUC approval.

Standard	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
PER-006-1	None reported.	None reported.	None reported.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter, 24 months after BCUC adoption. Feedback Exceptions: FortisBC – Immediately after BCUC approval.
PRC-025-2	None reported.	BC Hydro –\$20,000; relay loadability checking of 29 BC Hydro transmission lines connected to BC Hydro generation stations will need to be performed to align with PRC-025-2 revisions. Northwood Pulp Mill – \$30,000; need verification of the relay settings on generator protection relays and Generation Step-Up "GSU" transformer protection relays to see if we are in compliance with this standard	BC Hydro - \$10,000; annual ongoing maintenance verification for relay loadability	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter after BCUC adoption. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C.-specific version of the PRC-025-2 Implementation Plan be implemented in B.C pursuant to an order of the BCUC providing for the administration of adopted reliability standards. Please refer to section 2.4 of the Report. Feedback Exceptions: FortisBC – Immediately after BCUC approval. Northwood Pulp Mill – Six months from the implementation of this standard by BCUC.

Standard	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
PRC-027-1	None reported.	BC Hydro – R1: \$1,000,000; review/update short-circuit model data, review developed Protection System settings, coordinate Protection System settings that electrically join Facilities owned by separate functional entities, verify that identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation, communicate with other owner(s) of joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances, and establish associated processes and evidence. R2: \$200,000; perform Protection System Coordination Studies. R3: \$50,000; develop new and revised Protection System settings for BES Elements pursuant to process established per PRC-027-1 R1. Catalyst Paper (Crofton, Port Alberni, Powell River) – R1: \$100,000; New process required and a new system study. R2: \$100,000; New process required and a new system study. R3: \$50,000; New relay settings required. FortisBC – \$75,000 – \$100,000 FortisBC will need to establish a new process for developing new and revised Protection System settings and perform a Protection System Coordination Study for each BES element in the FortisBC system. Northwood Pulp Mill – R1: \$30,000; Review of Short Circuit model will need to be done, plus verifications of the protection settings to be completed R2: \$30,000; Review of Short Circuit model will need to be done, plus verifications of the protection settings to be completed R3: \$30,000; Review of Short Circuit model will need to be done, plus verifications of the protection settings to be completed.	BC Hydro – R1: \$100,000; ongoing reviews and updates of short-circuit model data, Protection System settings, coordination with other functional entities, and processes. R2: \$200,000 per six years; perform periodic Protection System Coordination Studies. R3: \$50,000; annual reviews/audits of Protection System settings. Catalyst Paper (Crofton, Port Alberni, Powell River) – R1: \$20,000; New process required and a new system study. R2: \$20,000; New process required and a new system study. R3: \$10,000; New relay settings required.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter, 24 months after BCUC adoption. Initial performance of R2: For each option under R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of R2 must establish an initial Fault current baseline by the effective date of PRC-027-1. Feedback Exceptions: Catalyst Paper (Crofton, Port Alberni, Powell River) – R1 and R2 - 18 months after BCUC approval. R3 – Two years after BCUC approval. FortisBC –24 months after BCUC approval. Northwood Pulp Mill – Six months from the implementation of the standard by BCUC.

Standard	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
VAR-001-5	None reported.	None reported.	None reported.	BC Hydro's Consolidated Recommendation: First day of the first calendar quarter after BCUC adoption. Feedback Exceptions: FortisBC – Immediately after BCUC approval.
VAR-002-WECC-2	None reported.	None reported.	None reported.	Retire immediately after BCUC approval.

1. Retired Standard BAL-004-0 Requirements 1 and 4 are applicable to RCs only. Requirement 1 requires appointment by the NERC Operating Committee to identify a single RC per Interconnection (for B.C., the Western Interconnection) to serve as the Interconnection Time Monitor and Requirement 4 authorizes RCs to make requests of the identified Interconnection Time Monitor to terminate a Time Error Correction due to reliability considerations. As this standard is being retired, there are no perceived suitability issues given that this requirement currently only applies to Peak Reliability as the RC for B.C. and the Western Interconnection.
2. Revised Standard EOP-004-4 Requirement 1 requires entities to report events to the ERO. In the U.S. the ERO is NERC; however, there is no ERO in B.C. Entities subject to MRS are not required to report to NERC, because B.C. is outside of NERC's jurisdiction; however, entities may report to NERC on a voluntary basis. There are no perceived suitability issues that would impact a B.C. entity's ability to comply with the identified Reliability Standard requirements. Similar ERO event reporting requirements exist within the BCUC adopted and effective EOP-004-3 standard Requirement 1 for which entities have not been required to report events to NERC.
3. Revised Standard EOP-004-4 Requirements 1 and 2 and EOP-008-2 Requirement 8 requires entities to report events and provide plans, respectively, to their "Regional Entity". WECC is the BCUC's designated compliance administrator in B.C., so there are no perceived suitability issues that would impact a B.C. entity's ability to comply with the identified Revised Standard requirements.

1 BC Hydro's assessment is that all 13 Revised Standards and two Retired Standards
2 should be recommended to the BCUC for adoption and retirement respectively in
3 B.C. as they will either maintain or promote the reliability of the BES in B.C.

4 BC Hydro also recommends the retirement of the two Retired Standards.

5 The total cumulative cost required to adopt the 13 Revised Standards in B.C. is
6 estimated to be a minimum of \$27,051,500 for their implementation, with ongoing
7 annual costs of a minimum of \$6,155,833 to maintain compliance. The cost
8 estimates are the cumulative costs provided by the stakeholders that responded to
9 the survey, including BC Hydro.

- 10 • BC Hydro reported estimated incremental one-time costs of at least
11 \$26,306,500. Annual ongoing costs are estimated to be at least \$6,055,833;⁷
- 12 • Catalyst Paper – Crofton, Port Alberni, and Powell River Divisions reported
13 estimated incremental one-time costs of at least \$300,000. Annual ongoing
14 costs are estimated to be \$70,000. FortisBC Inc. reported estimated incremental
15 one-time costs of at least \$325,000. Annual ongoing costs are estimated to be
16 \$30,000; and
- 17 • Northwood Pulp Mill reported estimated incremental one-time costs of at least
18 \$120,000. Annual ongoing costs are estimated to be \$0.

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

⁷ Includes one time and annual ongoing costs related to RC function.

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;
- 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 Revised Standards and Retired Standards assessed by BC Hydro in this report are based on the defined terms contained in the NERC Glossary dated July 3, 2018. Accordingly, BC Hydro is attaching the July 3, 2018 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 Revised Standards in order to achieve and maintain consistency with NERC reliability standards going forward, provided that:

- Any NERC Glossary terms and definitions in the NERC Glossary that are not approved by FERC on or before November 30, 2018 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.; and
- Any FERC approved NERC Glossary terms which 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

1 reliability standards that have not yet been assessed or adopted in B.C. are of
2 no force or effect in B.C.

3 **6.1 Non-FERC Approved and Remanded/Retired NERC Glossary** 4 **Terms**

5 BC Hydro notes that new or revised NERC Glossary terms must not be approved for
6 adoption in B.C. until they are assessed by BC Hydro and included in an
7 assessment report. NERC Glossary terms that are not identified as being FERC
8 approved in the NERC Glossary as part of the assessment process could become
9 FERC approved at any time thereafter. These new or revised terms could have
10 impacts on the reliability standards adopted in B.C. BC Hydro recommends that
11 NERC Glossary terms and definitions used in reliability standards, that are not
12 identified in the July 3, 2018 version of the NERC Glossary as having a FERC
13 approval date on or before November 30, 2018 should be of no force or effect
14 in B.C.

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

6.2 NERC Glossary Terms Assessed by BC Hydro

BC Hydro has assessed five Revised Terms in the Report. As provided in Appendix B, the July 3, 2018 version of the NERC Glossary contains five Revised Terms that have been adopted by NERC and approved by FERC within the 2018 Assessment Period. The list of Revised Terms assessed in the Report are provided in Appendix A-1, and includes a reference to the FERC approval and retirement dates.

6.3 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 Revised Standards and Retired Standards. 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;
- 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

- 1 • The “Suitability Issues” columns, which identify potential suitability issues
2 related to Revised Terms superseding BCUC approved NERC Glossary terms:
 - 3 ▶ Requires NERC Approval/Participation: Identifies a potential Administrative
4 or Technical Suitability issue as related to continued reliance on approvals
5 by NERC and/or participation in NERC in order to implement the definition of
6 a Revised Term;
 - 7 ▶ Requires Provisions of Information to NERC or WECC: Identifies a potential
8 Administrative or Technical Suitability issue with a Revised Term and its
9 definition that requires ongoing reporting of information to NERC or WECC
10 (i.e., lack of clarity on reporting instructions, references to undefined
11 processes or reporting tools, etc.);
 - 12 ▶ Refers to Standard, Term, or Definition not yet FERC Approved: Identifies a
13 potential Technical or Administrative Suitability issue with a Revised Term
14 and/or its definition as it contains one or more references to reliability
15 standards or other NERC Glossary terms and associated definitions that
16 have not yet been approved by FERC in the U.S., and thereby not assessed
17 for adoption in B.C. This would affect the ability to implement the Revised
18 Term and its definition; and
 - 19 ▶ Other Suitability Issues: Identifies whether there are any other
20 Administrative or Technical Suitability issues identified, apart from the
21 categories already defined, that would affect the ability to implement
22 the Revised Term and its definition.

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

	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 Term or Definition not yet FERC Approved	Other Suitability Issues
					To NERC	To WECC		
1	Operational Planning Analysis (OPA)	Yes	No	No	No	No	No	No
2	Protection System Coordination Study	New	No	No	No	No	No	No
3	Real-time Assessment	Yes	No	No	No	No	No	No
4	Removable Media	Yes	No	No	No	No	No	No
5	Transient Cyber Asset (TCA)	Yes	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 five 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;⁸
- 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 make reference 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, for the Revised

⁸ No adverse reliability consequences were identified during the final assessment of the Revised Terms.

1 Terms. BC Hydro recommends that these recommended Effective Dates be
2 adopted by the BCUC.

3 **Table 5 Final Assessment Summary of NERC**
4 **Glossary Terms**

NERC Glossary Term	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
Operational Planning Analysis (OPA)	None reported.	BC Hydro – Refer to costs associated with Revised Standard PER-006-1.	BC Hydro – Refer to costs associated with Revised Standard PER-006-1.	BC Hydro's Consolidated Recommendation: Coincide with effective date of Revised Standard PER-006-1 after BCUC adoption. Feedback Exceptions: FortisBC – Immediately after BCUC approval.
Protection System Coordination Study	None reported.	BC Hydro – Refer to costs associated with Revised Standard PRC-027-1. Catalyst Paper (Crofton, Port Alberni, Powell River) – Included with Revised Standard PRC-027-1 costs. FortisBC – Refer to Revised Standard PRC-027-1 costs.	BC Hydro – Refer to costs associated with Revised Standard PRC-027-1. Catalyst Paper (Crofton, Port Alberni, Powell River) – Included with Revised Standard PRC-027-1 costs. FortisBC – Refer to Revised Standard PRC-027-1 costs.	BC Hydro's Consolidated Recommendation: Coincide with effective date of Revised Standard PRC-027-1 after BCUC adoption. Feedback Exceptions: Catalyst Paper (Crofton, Port Alberni, Powell River) – Two years after BCUC adoption.
Real-time Assessment (RTA)	None reported.	BC Hydro – See costs associated with Revised Standard PER-006-1.	BC Hydro – Refer to costs associated with Revised Standard PER-006-1.	BC Hydro's Consolidated Recommendation: Coincide with effective date of Revised Standard PER-006-1 after BCUC adoption. Feedback Exceptions: FortisBC – Immediately after BCUC approval.
Removable Media	None reported.	BC Hydro – See costs associated with Revised Standard CIP-003-7. Catalyst Paper (Crofton, Port Alberni, Powell River) – Refer to Revised Standard CIP-003-7 costs.	BC Hydro – See costs associated with Revised Standard CIP-003-7. Catalyst Paper (Crofton, Port Alberni, Powell River) – Refer to Revised Standard CIP-003-7 costs.	BC Hydro's Consolidated Recommendation: Coincide with effective date of Revised Standard CIP-003-7 after BCUC adoption. Feedback Exceptions: Catalyst Paper (Crofton, Port Alberni, Powell River) – One year after BCUC approval. FortisBC – Immediately after BCUC approval.

NERC Glossary Term	Suitability Issues	One-time Cost (\$)	Ongoing Cost (\$/year)	Recommended Effective Date
Transient Cyber Asset (TCA)	None reported.	BC Hydro – Refer to costs associated with Revised Standard CIP-003-7. Catalyst Paper (Crofton, Port Alberni, Powell River) – Refer to Revised Standard CIP-003-7 costs.	BC Hydro – Refer to costs associated with Revised Standard CIP-003-7 standard. Catalyst Paper (Crofton, Port Alberni, Powell River) – Refer to Revised Standard CIP-003-7 costs.	BC Hydro's Consolidated Recommendation: Coincide with effective date of Revised Standard CIP-003-7 after BCUC adoption. Feedback Exceptions: Catalyst Paper (Crofton, Port Alberni, Powell River) – One year after BCUC approval. FortisBC – Immediately after BCUC approval.

BC Hydro's assessment is that all five assessed Revised Terms will either maintain or promote the reliability of the BES in B.C. Based on the assessment above, the minimum total costs required to adopt these five Revised Terms is estimated to be shared with the costs of implementing the associated standards as indicated in section [5.3](#).

7 Conclusions

BC Hydro has assessed 13 Revised Standards and two Retired Standards adopted and retired respectively by FERC during the 2018 Assessment Period in the Report.

BC Hydro has concluded that all 13 Revised 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 in B.C. BC Hydro recommends that these 13 Revised Standards and two Retired Standards be adopted and retired respectively by the BCUC and should have effective dates that are based on the recommended effective dates included in [Table 3](#), section [5.3](#) and Attachment A to Appendix D.

As discussed in sections [2.3](#) and [2.4](#), in connection with the recommendation to adopt the CIP-003-7 and PRC-025-2 Revised Standards, BC Hydro recommends that B.C.-specific versions of the CIP-003-7 and PRC-25-2 Implementation Plans be

1 incorporated into the B.C. MRS program pursuant to an order of the BCUC providing
2 for the administration of adopted reliability standards. BC Hydro has provided
3 B.C.-specific versions of the CIP-003-7 and PRC-25-2 Implementation Plans, clean
4 and redlined, to show changes from the documents developed by NERC, in
5 Attachment D to Appendix D for the BCUC's consideration.

6 BC Hydro has assessed five Revised Terms in the Report. The five Revised Terms
7 were adopted by FERC during the 2018 Assessment Period.

8 BC Hydro has concluded that all five Revised Terms assessed in the Report will
9 preserve or enhance the reliability of the BES in B.C., and thus will serve the public
10 interest and are suitable for adoption in B.C. BC Hydro recommends that these
11 five Revised Terms be adopted by the BCUC and should have effective dates that
12 are based on the recommended effective dates included in [Table 5](#), section [6.4](#) and
13 Attachment A to Appendix D.

14 Regarding the replacement of 13⁹ BCUC approved reliability standards and the
15 four BCUC approved NERC Glossary terms being superseded by the Revised
16 Standards and Revised Terms respectively, BC Hydro recommends that, to avoid
17 duplication, these currently approved reliability standards and NERC Glossary terms
18 be ordered to remain in effect until the effective date of the superseding Revised
19 Standard or Revised Term.

⁹ Refer to Appendix A-1 for a list of BCUC approved reliability standards that would be superseded by reliability standards assessed in the Report.

Mandatory Reliability Standards Assessment Report No. 12

Appendix A-1

List of Assessed Reliability Standards and NERC Glossary Terms

Table 1 Reliability Standards Assessed

	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	BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	Docket No. RD18-7-000; Issued September 25, 2018	September 25, 2018	April 01, 2019	Revised	BAL-002-2
2	BAL-004-0	Time Error Correction	Docket No. RD17-1-000; Issued January 18, 2017	January 18, 2017	April 01, 2017	Retired	N/A – Retired Standard
3	BAL-004-WECC-3	Automatic Time Error Correction	Docket No. RD18-2-000; Issued May 30, 2018	May 30, 2018	October 01, 2018	Revised	BAL-004-WECC-2
4	CIP-003-7	Cyber Security — Security Management Controls	Docket No. RM17-11-000; Order No. 843; Issued April 19, 2018; Published April 25, 2018	June 25, 2018	Jan 01, 2020	Revised	CIP-003-5
5	EOP-004-4	Event Reporting	Docket No. RM17-12-000; Order No. 840; Issued January 18, 2018 Published January 24, 2018	March 26, 2018	April 01, 2019	Revised	EOP-004-3
6	EOP-005-3	System Restoration from Blackstart Resources	Docket No. RM17-12-000; Order No. 840; Issued January 18, 2018 Published January 24, 2018	March 26, 2018	April 01, 2019	Revised	EOP-005-2

	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	EOP-006-3	System Restoration Coordination	Docket No. RM17-12-000; Order No. 840; Issued January 18, 2018 Published January 24, 2018	March 26, 2018	April 01, 2019	Revised	EOP-006-2
8	EOP-008-2	Loss of Control Center Functionality	Docket No. RM17-12-000; Order No. 840; Issued January 18, 2018 Published January 24, 2018	March 26, 2018	April 01, 2019	Revised	EOP-008-1
9	FAC-501-WECC-2	Transmission Maintenance	Docket No. RD18-5-000; Issued May 30, 2018	May 30, 2018	July 01, 2018	Revised	FAC-501-WECC-1
10	PER-003-2	Operating Personnel Credentials	Docket No. RD18-9-000 Issued November 21, 2018	November 21, 2018	July 01, 2019	Revised	PER-003-1 and PER-004-2
11	PER-006-1	Specific Training for Personnel	Docket No. RM16-22-000; Order No. Issued June 7, 2018 Published June 13, 2018	August 13, 2018	October 01, 2020	New	PRC-001-1.1(ii) R1
12	PRC-025-2	Generator Relay Loadability	Docket No. RD18-4-000; Issue Date: May 2, 2018	May 02, 2018	July 01, 2018	Revised	PRC-025-1
13	PRC-027-1	Coordination of Protection Systems for Performance During Faults	Docket No. RM16-22-000; Order No. 847; Issued June 7, 2018 Published June 13, 2018	August 13, 2018	October 01, 2020	New	PRC-001-1.1(ii) R3 and R4
14	VAR-001-5	Voltage and Reactive Control	Docket No. RD18-8-000; Issued October 15, 2018	October 15, 2018	January 01, 2019	Revised	VAR-001-4.2
15	VAR-002-WECC-2	Voltage and Reactive Control	Docket No. RD18-1-000; Issued September 5, 2018	September 5, 2018	September 5, 2018	Retired	N/A-Retired Standard

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	Operational Planning Analysis	OPA	Operational Planning Analysis	June 7, 2018	October 1, 2020
2	Protection System Coordination Study	N/A	N/A; New Term	June 7, 2018	October 1, 2020
3	Real-time Assessment	RTA	Real-time Assessment	June 7, 2018	October 1, 2020
4	Removable Media	N/A	Removable Media	April 19, 2018	January 1, 2020
5	Transient Cyber Asset	TCA	Transient Cyber Asset	April 19, 2018	January 1, 2020

**Mandatory Reliability Standards
Assessment Report No. 12**

Appendix A-2

Reliability Standards Assessed by BC Hydro

Clean

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-3
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**
 - 4.1. **Responsible Entity**
 - 4.1.1. Balancing Authority
 - 4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.
 - 4.1.2. Reserve Sharing Group
5. ~~**Effective Date:** See the Implementation Plan for BAL-002-3.~~

B. Requirements and Measures

- R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:
[Violation Risk Factor: High] [Time Horizon: Real-time Operations]
 - 1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:
 - zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,or,
 - its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.
 - 1.2. document all Reportable Balancing Contingency Events using CR Form 1.

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- 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, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

- M2.** Each Responsible Entity will have the following documentation to show compliance with Requirement R2:
- a dated Operating Process;
 - evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
 - evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.
- R3.** Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- M3.** Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

**BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a
Balancing Contingency Event**

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

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

1.3. 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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

Supplemental Material

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	
3	August 16, 2018	Adopted by NERC Board of Trustees	Revisions to address two FERC directives from Order No. 835
3	September 25, 2018	FERC Order approving BAL-002-3. Docket No. RD18-7-000	

A. Introduction

- 1. Title:** Automatic Time Error Correction
- 2. Number:** BAL-004-WECC-3
- 3. Purpose:** To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.
- 4. Applicability**
 - 4.1. Functional Entities**
 - 4.1.1** Balancing Authorities that operate synchronously in the Western Interconnection.
- ~~**5. Effective Date:** On the first day of the second quarter, after applicable regulatory approval has been received (or the Reliability Standard otherwise becomes effective the first day of the fourth quarter following NERC Board adoption where regulatory approval is not required).~~

B. Requirements and Measures

- R1.** Each Balancing Authority shall operate its system such that, following the conclusion of each month, the month-end absolute value of its On-Peak and Off-Peak, Accumulated Primary Inadvertent Interchange (PII_{accum}), as calculated by the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, are each individually less than or equal to: *[Violation Risk Factor Medium:] [Time Horizon: Operations Assessment]*
 - 1.1** For load-serving Balancing Authorities, 150% of the previous calendar year's integrated hourly Peak Demand,
 - 1.2** For generation-only Balancing Authorities, 150% of the previous calendar year's integrated hourly peak generation.
- M1.** Each Balancing Authority will have evidence that it operated its system such that, following the conclusion of each month, the month-end absolute value of its On-Peak and Off-Peak, Accumulated Primary Inadvertent Interchange (PII_{accum}), as calculated by the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, meets all criteria stated in Requirement R1.
- R2.** Each Balancing Authority shall, upon discovery of an error in the calculation of PII_{hourly} , recalculate within 90 days, the value of PII_{hourly} and adjust the PII_{accum} from the time of the error. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
 - M2.** Forms of acceptable evidence of compliance with Requirement R2 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool (WIT) or its successor electronic confirmation tool,
- Data, screen shots from the internal Balancing Authority tool, or
- Production of data from any other databases, spreadsheets, displays.

R3. Each Balancing Authority shall keep its Automatic Time Error Correction (ATEC) in service, with an allowable exception period of less than or equal to an accumulated 24 hours per calendar quarter for ATEC to be out of service. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M3. Forms of acceptable evidence of compliance with Requirement R3 may include, but are not limited to:

- Dated archived files,
- Historical data,
- Other data that demonstrates the ATEC was out of service for less than 24 hours per calendar quarter.

R4. Each Balancing Authority shall compute each of the following using the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, no later than 50 minutes after each hour,

4.1. $P_{II_{hourly}}$,

4.2. $P_{II_{accum}}$,

4.3. Automatic Time Error Correction term (I_{ATEC}).

[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

M4. Forms of acceptable evidence of compliance with Requirement R4 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, that demonstrate compliance;
- Data, screen shots from internal Balancing Authority tool that demonstrate compliance; or,
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

R5. Each Balancing Authority shall be able to change its Automatic Generation Control operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; and Tie Line Bias plus Time Error Control (used in ATEC mode), to correspond to current operating conditions. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

- M5.** Forms of acceptable evidence of compliance with Requirement R5 include but are not limited to any one of the following:
- Screen shots from Energy Management System,
 - Demonstration using an off-line system.
- R6.** Each Balancing Authority shall recalculate the PIIhourly and PIIaccum for the On-Peak and Off-Peak periods whenever adjustments are made to hourly Inadvertent Interchange or ΔTE . *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M6.** Forms of acceptable evidence of compliance with Requirement R6 include but are not limited to any one of the following:
- Data, screen shots from the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, that demonstrate compliance;
 - Data, screen shots from an internal Balancing Authority tool that demonstrate compliance with; or,
 - Data from any other databases, spreadsheets, displays that demonstrate compliance.
- R7.** Each Balancing Authority shall make the same adjustment to the PIIaccum as it did for any month-end meter reading adjustments to Inadvertent Interchange. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M7.** Forms of acceptable evidence of compliance with Requirement R7 include but are not limited to any one of the following:
- Data, screen shots from the WECC Interchange Tool (WIT) or its successor electronic confirmation tool, that demonstrate compliance;
 - Data, screen shots from an internal Balancing Authority tool that demonstrate compliance; or,
 - Production of data from any other databases, spreadsheets, displays that demonstrate compliance.
- R8.** Each Balancing Authority shall payback Inadvertent Interchange using ATEC rather than bilateral and unilateral payback. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M8.** Forms of acceptable evidence of compliance with Requirement R8 include but are not limited to historical On-Peak and Off-Peak Inadvertent Interchange data, data from the WECC Interchange Tool, and ACE data.

C. Compliance**1. Compliance Monitoring Process****1.1 Compliance Enforcement Authority**

The Regional Entity shall serve as the Compliance Enforcement Authority.

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3 Evidence Retention

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

Each Balancing Authority in the Western Interconnection shall retain the values of PII_{hourly} , PII_{accum} (On-Peak and Off-Peak), ΔTE and any month-end adjustments for the preceding calendar year (January – December), as well as the current calendar year.

Each Balancing Authority in the Western Interconnection shall retain the amount of time the Balancing Authority operated without ATEC for the preceding calendar year (January – December), as well as the current calendar year.

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	Operations Assessment	Medium	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 150%, but was less than or equal to 160% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 160%, but was less than or equal to 170% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 170%, but was less than or equal to 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.
R2	Operations Assessment	Medium	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 90 days of the discovery of the error; but made the required recalculations and adjustments within 120 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 120 days of the discovery of the error; but made the required recalculations and adjustments within 150 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 150 days of the discovery of the error; but made the required recalculations and adjustments within 180 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust PII_{accum} within 180 days of the discovery of the error.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Real-Time Operations	Medium	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 24 hours, but less than or equal to 72 hours.	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 72 hours, but less than or equal to 120 hours.	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 120 hours, but less than or equal to 168 hours	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 168 hours.
R4	Operations Assessment	Medium	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within 50 minutes, but made the required calculations in less than or equal to two hours.	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within two hours, but made the required calculations in less than or equal to four hours.	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within four hours, but made the required calculations in less than or equal to six hours.	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within six hours.
R5	Real-Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority is not able to change its AGC operating mode between Flat Frequency (for blackout restoration; Flat Tie Line (for loss of frequency

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						telemetry); Tie Line Bias; or Tie Line Bias plus Time Error control (used in ATEC mode).
R6	Operations Assessment	Medium	N/A	N/A	N/A	When making adjustments to hourly Inadvertent Interchange or ΔTE , the Balancing Authority did not recalculate the PII_{hourly} and the PII_{accum} for the On-Peak and Off-Peak periods.
R7	Operations Assessment	Medium	N/A	N/A	N/A	When making any month-end meter reading adjustments to Inadvertent Interchange, the Balancing Authority did not make the same adjustment to the PII_{accum} .

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R8	Operations Assessment	Medium	N/A	N/A	N/A	The Balancing Authority paid back Inadvertent Interchange using bilateral and unilateral payback rather than using ATEC.

Guidelines and Technical Basis**Background**

In February 2003, the WECC Automatic Time Error Correction (ATEC) Procedure (Procedure) became effective for all Balancing Authorities in the Western Interconnection. The original intent of the Procedure was to minimize the number of Manual Time Error Corrections in the Western Interconnection. ATEC provides the added benefit of a superior approach over NERC Reliability Standard BAL-004-0 – Time Error Correction for assigning costs and providing for the equitable payback of Inadvertent Interchange. In October 2006, the Procedure became a WECC Criterion. In May 2009, FERC issued Order No.723 that approved Regional Reliability Standard BAL-004-WECC-1 - Automatic Time Error Correction, as submitted by NERC. In addition, the Commission directed WECC to develop several clarifying modifications to BAL-004-WECC-1 using the FERC-approved Process for Developing and Approving WECC Standards. The Effective Date of the BAL-004-WECC-1 standard was July 1, 2009. BAL-004-WECC-1 required Balancing Authorities within the Western Interconnection to maintain Interconnection frequency within a predefined frequency profile and to ensure that Time Error Corrections were effectively conducted in a manner that did not adversely affect the reliability of the Interconnection. In September 2009, WECC received WECC Standards/Regional Criterion Request Form (Request) WECC-0068, which was a request for modification of BAL-004-WECC-1. In July 2010, the chair of the WECC Operating Committee assigned the Request to the Performance Work Group (PWG) for development.

Requirement R1:

Premise: Each Balancing Authority should ensure that the absolute value of its PII_{accum} for both the On- Peak period and the Off-Peak period each individually does not exceed 150% of the previous year's Peak Demand for load-serving Balancing Authorities and 150% of the previous year's peak generation for generation-only Balancing Authorities. The Balancing Authority is required to keep each PII_{accum} period within the limit. For example, the Balancing Authorities actions may include:

- Identifying and correcting the source of any metering or accounting error(s) and recalculating the hourly Primary Inadvertent Interchange (PII_{hourly}) and the PII_{accum} from the time of the error;
- Validating the implementation of ATEC; or
- Setting L_{max} equal to L_{10} until the PII_{accum} is below the limit in Requirement R1.

Justification: PII_{accum} may grow from month-end adjustments and metering errors, even with the inclusion of I_{ATEC} in the ACE equation.

Goal: To limit the amount of PII_{accum} that a Balancing Authority can have at the end of each month.

Requirement R2:

Premise: When a Balancing Authority finds an error in the calculation of its PII, the Balancing Authority needs time to correct the error and recalculate PII and PII_{accum} .

Justification: The drafting team selected 90 days as a reasonable amount of time to correct an error and recalculate PII and PII_{accum} , since recalculation of PII and PII_{accum} is not a real-time operations reliability issue.

Goal: To promote the timely correction of errors in the calculation of PII and PII_{accum} .

Requirement R3:

Premise: When a Balancing Authority is not participating in ATEC, payback of PII_{accum} is delayed.

Justification: The limit of 24 hours per quarter discourages a Balancing Authority from withdrawing ATEC participation, for example, for economic gain during selected hours. If the limits were increased to 60 hours, a Balancing Authority could technically withdraw ATEC participation for one hour from Monday to Friday.

Goal: To promote fair and timely payback of PII_{accum} balances.

Requirement R4:

Premise: PII_{hourly} , PII_{accum} , and I_{ATEC} should be determined before the next scheduling hour begins.

Justification: To promote timely calculations 50 minutes was selected because it is before the next hour ramp begins and permits time to collect the data and resolve interchange metering values.

Goal: To promote the timely calculation of PII_{hourly} , PII_{accum} , and I_{ATEC} .

Requirement R5:

Premise: The ACE equation, and hence the AGC mode, will contain any number of parameters based on system operating conditions. Various AGC modes are identified corresponding to those operating conditions, as well as the specific sets of parameters included in the ACE equation.

Justification: Changing to the proper operating mode, corresponding to current operating conditions, affords proper movement of generating units in response to those conditions. The addition of the ATEC term results in an additional AGC mode and a different set of parameters. The inability to correctly calculate the ATEC term would dictate that AGC not be operated in the ATEC mode.

Goal: To set the AGC mode and calculate ACE in a manner that corresponds to the system operating conditions and to accommodate changes in those conditions.

Requirement R6:

Premise: Hourly adjustments to hourly Inadvertent Interchange (II) require a recalculation of

the corresponding hourly PII value, the corresponding PII_{accum} , and all subsequent PII_{accum} for every hour up to the current hour.

Justification: As PII_{hourly} is corrected, then PII_{accum} should be recalculated.

Goal: To promote accurate, fair and timely payback of accumulated PII balances.

Requirement R7:

Premise: Month-end meter-reading adjustments are made, for example, when a Balancing Authority performs monthly comparisons of recorded month-end Net Actual Interchange (NI_A) values derived from hourly Actual Interchange Telemetered Values against month-end Actual Interchange Register Meter readings.

Justification: Month-end adjustments to II_{accum} are applied as 100% PII_{accum} . 100% was chosen for simplicity to bilaterally assign PII_{accum} to both Balancing Authorities, since the effect of this metering error on system frequency is not easily determined over the course of a month.

Goal: To provide a mechanism by which corresponding month-end II adjustments can be **applied** to PII_{accum} , when such adjustments cannot be attributed to any one hour or series of hours.

Requirement R8:

Premise: ATEC includes automatic unilateral payback of Primary Inadvertent Interchange and Secondary Inadvertent Interchange.

Justification: Additional unilateral and bilateral exchanges disturb the balance and distribution between Primary Inadvertent Interchange and Secondary Inadvertent Interchange throughout the Interconnection; thereby stranding Secondary Inadvertent Interchange.

Goal: To not strand Secondary Inadvertent Interchange.

Version History

Version	Date	Action	Change Tracking
1	February 4, 2003	Effective Date.	New
1	October 17, 2006	Created Standard from Procedure.	Errata
1	February 6, 2007	Changed the Standard Version from 0 to 1 in the Version History Table.	Errata
1	February 6, 2007	The upper limit bounds to the amount of Automatic Time Error Correction term was inadvertently omitted during the Standard Translation. The bound was added to the requirement R1.4.	Errata
1	February 6, 2007	The statement “The Time Monitor may declare offsets in 0.001-second increments” was moved from TEoffset to TDadj and offsets was corrected to adjustments.	Errata
1	February 6, 2007	The reference to seconds was deleted from the TE offset term.	Errata
1	June 19, 2007	The standard number BAL-STD-004-1 was changed to BAL-004-WECC-01 to be consistent with the NERC Regional Reliability Standard Numbering Convention.	Errata
2	December 19, 2012	Adopted by NERC Board of Trustees.	
2	October 16, 2013	A FERC Letter Order was issued on October 16, 2013, approving BAL-004-WECC-02. This standard will become enforceable on April 1, 2014.	

Version	Date	Action	Change Tracking
3	December 6, 2017	Approved by the WECC Board of Directors.	Five-year review. The project: 1) relocates the Background section to the preamble of the Guidance section, 2) adds On-Peak and Off-Peak parameters in Requirement R1/M1, 3) addresses WECC Interchange Tool software successors throughout, 4) conforms the document to current drafting conventions (R1/M1, R4/M4), and, 5) addresses non-substantive syntax and template concerns.
3	February 8, 2018	Approved by the NERC Board of Trustees.	

A. Introduction

- 1. Title:** Cyber Security — Security Management Controls
- 2. Number:** CIP-003-7
- 3. Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).
- 4. Applicability:**
 - 4.1. Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. Balancing Authority**
 - 4.1.2. Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1.** Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2.** Each Special Protection System (SPS) or Remedial Action Scheme (RAS) where the SPS or RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3. Generator Operator**
 - 4.1.4. Generator Owner**
 - 4.1.5. Interchange Coordinator or Interchange Authority**
 - 4.1.6. Reliability Coordinator**

4.1.7. Transmission Operator**4.1.8. Transmission Owner**

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

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

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

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

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

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

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-003-7:

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

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

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

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

~~5. Effective Dates:~~

~~See Implementation Plan for CIP-003-7.~~

6. Background:

Standard CIP-003 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements.

The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high, medium, and low impact BES Cyber Systems. For example, a single cyber security awareness program could meet the requirements across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

- R1.** Each Responsible Entity shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 1.1.** For its high impact and medium impact BES Cyber Systems, if any:
 - 1.1.1.** Personnel and training (CIP-004);
 - 1.1.2.** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
 - 1.1.3.** Physical security of BES Cyber Systems (CIP-006);
 - 1.1.4.** System security management (CIP-007);
 - 1.1.5.** Incident reporting and response planning (CIP-008);
 - 1.1.6.** Recovery plans for BES Cyber Systems (CIP-009);
 - 1.1.7.** Configuration change management and vulnerability assessments (CIP-010);
 - 1.1.8.** Information protection (CIP-011); and
 - 1.1.9.** Declaring and responding to CIP Exceptional Circumstances.
 - 1.2.** For its assets identified in CIP-002 containing low impact BES Cyber Systems, if any:
 - 1.2.1.** Cyber security awareness;
 - 1.2.2.** Physical security controls;
 - 1.2.3.** Electronic access controls;
 - 1.2.4.** Cyber Security Incident response;
 - 1.2.5.** Transient Cyber Assets and Removable Media malicious code risk mitigation; and
 - 1.2.6.** Declaring and responding to CIP Exceptional Circumstances.
- M1.** Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
- R2.** Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall implement one or more documented cyber security plan(s) for its low impact BES Cyber Systems that include the sections in Attachment 1. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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

- M2.** Evidence shall include each of the documented cyber security plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate implementation of the cyber security plan(s). Additional examples of evidence per section are located in Attachment 2.
- R3.** Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium]*
[Time Horizon: Operations Planning]
- M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.
- R4.** The Responsible Entity shall implement a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower]* *[Time Horizon: Operations Planning]*
- M4.** An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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 Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.1) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.1) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.1) OR

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			complete this review in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1)	complete this review in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1)	calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact	The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.1)

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address one of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 15 calendar	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address two of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 within 16 calendar	BES Cyber Systems, but did not address three of the six topics required by R1. (R1.2) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1 within 17 calendar months but did not complete this review in less than or equal to 18 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its	OR The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems, but did not address four or more of the six topics required by R1. (R1.2) OR The Responsible Entity did not have any documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by R1. (R1.2) OR

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			months but did complete this review in less than or equal to 16 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of	months but did complete this review in less than or equal to 17 calendar months of the previous review. (R1.2) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 16 calendar months but did complete this approval in less than or equal to 17	assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1.2)	The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R1.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1.2)	calendar months of the previous approval. (R1.2)		
R2	Operations Planning	Lower	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity implemented electronic access controls but failed to document its cyber security plan(s) for electronic access controls according to Requirement R2,	The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to reinforce cyber security practices at least once every 15 calendar months according to Requirement R2, Attachment 1, Section 1. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed	The Responsible Entity documented the physical access controls for its assets containing low impact BES Cyber Systems, but failed to implement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls for its assets containing low impact BES Cyber Systems, but failed to permit only necessary inbound and outbound electronic	The Responsible Entity failed to document and implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document one or more Cyber Security Incident response plan(s) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing	to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document electronic access controls according to Requirement R2, Attachment 1, Section 3. (R2) OR The Responsible Entity documented its cyber security plan(s) for electronic access controls but	access controls according to Requirement R2, Attachment 1, Section 3.1. (R2) OR The Responsible Entity documented one or more Cyber Security Incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to test each Cyber Security Incident response plan(s) at least once every 36 calendar months according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented the determination of	

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to Requirement R2, Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented	failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2) OR The Responsible Entity documented one or more incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents	whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2,	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			its plan(s) for Transient Cyber Assets, but failed to document the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2)	according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2,	Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 4. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Sections 5.1 and 5.3. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber	the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System according to Requirement R2, Attachment 1, Section 5.3. (R2)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media section(s) according to Requirement R2,		

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				Attachment 1, Section 5.3. (R2)		
R3	Operations Planning	Medium	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	Operations Planning	Lower	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

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

Version	Date	Action	Change Tracking
6	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
6	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
6	1/21/16	FERC Order issued approving CIP-003-6. Docket No. RM15-14-000	
7	2/9/17	Adopted by the NERC Board of Trustees.	Revised to address FERC Order No. 822 directives regarding (1) the definition of LERC and (2) transient devices.

Attachment 1

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

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

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

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

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

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

- 3.1** Permit only necessary inbound and outbound electronic access as determined by the Responsible Entity for any communications that are:
 - i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);
 - ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and
 - iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).
- 3.2** Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

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

- 4.1** Identification, classification, and response to Cyber Security Incidents;
- 4.2** Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the

Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;

- 4.3 Identification of the roles and responsibilities for Cyber Security Incident response by groups or individuals;
- 4.4 Incident handling for Cyber Security Incidents;
- 4.5 Testing the Cyber Security Incident response plan(s) at least once every 36 calendar months by: (1) responding to an actual Reportable Cyber Security Incident; (2) using a drill or tabletop exercise of a Reportable Cyber Security Incident; or (3) using an operational exercise of a Reportable Cyber Security Incident; and
- 4.6 Updating the Cyber Security Incident response plan(s), if needed, within 180 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident.

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

- 5.1 For Transient Cyber Asset(s) managed by the Responsible Entity, if any, the use of one or a combination of the following in an ongoing or on-demand manner (per Transient Cyber Asset capability):
 - Antivirus software, including manual or managed updates of signatures or patterns;
 - Application whitelisting; or
 - Other method(s) to mitigate the introduction of malicious code.
- 5.2 For Transient Cyber Asset(s) managed by a party other than the Responsible Entity, if any, the use of one or a combination of the following prior to connecting the Transient Cyber Asset to a low impact BES Cyber System (per Transient Cyber Asset capability):
 - Review of antivirus update level;
 - Review of antivirus update process used by the party;
 - Review of application whitelisting used by the party;
 - Review use of live operating system and software executable only from read-only media;
 - Review of system hardening used by the party; or
 - Other method(s) to mitigate the introduction of malicious code.

- 5.3** For Removable Media, the use of each of the following:
 - 5.3.1** Method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System; and
 - 5.3.2** Mitigation of the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System.

Attachment 2

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

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

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

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

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

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

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

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

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

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

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

1. Examples of evidence for Section 5.1 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.
2. Examples of evidence for Section 5.2 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that

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

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

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

In developing policies in compliance with Requirement R1, the number of policies and their content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-7, Requirement R1.

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any assets containing low impact BES Cyber Systems, the one or more cyber security policies must cover the six subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-7, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-003 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements in NERC cyber security Reliability Standards, but to develop a holistic cyber security policy

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appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel and training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

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

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN "split-tunneling" or "dual-homed" workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity's Interactive Remote Access controls

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

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

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1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

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

- Availability of spare components
- Availability of system backups

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

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

For Part 1.2, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for assets containing low impact BES Cyber Systems, if any:

1.2.1 Cyber security awareness

- Method(s) for delivery of security awareness
- Identification of groups to receive cyber security awareness

1.2.2 Physical security controls

- Acceptable approach(es) for selection of physical security control(s)

1.2.3 Electronic access controls

- Acceptable approach(es) for selection of electronic access control(s)

1.2.4 Cyber Security Incident response

- Recognition of Cyber Security Incidents

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- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.2.5 Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

- Acceptable use of Transient Cyber Asset(s) and Removable Media
- Method(s) to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media
- Method(s) to request Transient Cyber Asset and Removable Media

1.2.6 Declaring and responding to CIP Exceptional Circumstances

- Process(es) to declare a CIP Exceptional Circumstance
- Process(es) to respond to a declared CIP Exceptional Circumstance

Requirements relating to exceptions to a Responsible Entity's security policies were removed because it is a general management issue that is not within the scope of a reliability requirement. It is an internal policy requirement and not a reliability requirement. However, Responsible Entities are encouraged to continue this practice as a component of their cyber security policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

The intent of Requirement R2 is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that address the security objective for the protection of low impact BES Cyber Systems. The required protections are designed to be part of a program that covers the low impact BES Cyber Systems collectively at an asset level (based on the list of assets containing low impact BES Cyber Systems identified in CIP-002), but not at an individual device or system level.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be included in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. The purpose of the cyber security plan(s) in Requirement R2 is for Responsible Entities to use the cyber security plan(s) as a means of documenting their approaches to meeting the subject matter areas. The cyber security plan(s) can be used to reference other policies and procedures that demonstrate “how” the Responsible Entity is meeting each of the subject matter areas, or Responsible Entities can develop comprehensive cyber security plan(s) that contain all of the detailed implementation content solely within the cyber security plan itself. To meet the obligation for the cyber security plan, the expectation is that the cyber security plan contains or references sufficient details to address the implementation of each of the required subject matters areas.

Guidance for each of the subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The standard drafting team does not intend for Responsible Entities to be required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or “If you see something, say something” campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems within the asset, and (2) Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Attachment 1, Section 3.1, if any. If these Cyber Assets implementing the electronic access controls are located within the same asset as the low impact BES Cyber Asset(s) and inherit the same physical access controls and the same need as outlined in Section 2, this may be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility to select the methods used to meet the objective of controlling physical access to (1) the asset(s) containing low impact BES Cyber System(s) or the low impact BES Cyber Systems themselves and (2) the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a

combination of physical access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses.

The security objective is to control the physical access based on need as determined by the Responsible Entity. The need for physical access can be documented at the policy level. The standard drafting team did not intend to obligate an entity to specify a need for each physical access or authorization of an individual for physical access.

Monitoring as a physical security control can be used as a complement or an alternative to physical access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The standard drafting team's intent is that the monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective of controlling physical access.

User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of electronic access controls for assets containing low impact BES Cyber Systems when there is routable protocol communication or Dial-up Connectivity between Cyber Asset(s) outside of the asset containing the low impact BES Cyber System(s) and the low impact BES Cyber System(s) within such asset. The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity.

When implementing Attachment 1, Section 3.1, Responsible Entities should note that electronic access controls to permit only necessary inbound and outbound electronic access are required for communications when those communications meet all three of the criteria identified in Attachment 1, Section 3.1. The Responsible Entity should evaluate the communications and when all three criteria are met, the Responsible Entity must document and implement electronic access control(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the electronic access controls that meet their operational needs while meeting the security objective of allowing only necessary inbound and outbound electronic access to low impact BES Cyber Systems that use routable protocols between a low impact BES Cyber System(s) and Cyber Asset(s) outside the asset.

In essence, the intent is for Responsible Entities to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset or Dial-up Connectivity to the low impact BES Cyber System(s). Where such

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communication is present, Responsible Entities should document and implement electronic access control(s). Where routable protocol communication for time-sensitive protection or control functions between intelligent electronic devices that meets the exclusion language is present, Responsible Entities should document that communication, but are not required to establish any specific electronic access controls.

The inputs to this requirement are the assets identified in CIP-002 as containing low impact BES Cyber System(s); therefore, the determination of routable protocol communications or Dial-up Connectivity is an attribute of the asset. However, it is not intended for communication that provides no access to or from the low impact BES Cyber System(s), but happens to be located at the asset with the low impact BES Cyber System(s), to be evaluated for electronic access controls.

Electronic Access Control Exclusion

In order to avoid future technology issues, the obligations for electronic access controls exclude communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions, such as IEC TR-61850-90-5 R-GOOSE messaging. Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive characteristics related to this technology and not to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Considerations for Determining Routable Protocol Communications

To determine whether electronic access controls need to be implemented, the Responsible Entity has to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset.

When determining whether a routable protocol is entering or leaving the asset containing the low impact BES Cyber System(s), Responsible Entities have flexibility in identifying an approach. One approach is for Responsible Entities to identify an “electronic boundary” associated with the asset containing low impact BES Cyber System(s). This is not an Electronic Security Perimeter *per se*, but a demarcation that demonstrates the routable protocol communication entering or leaving the asset between a low impact BES Cyber System and Cyber Asset(s) outside the asset to then have electronic access controls implemented. This electronic boundary may vary by asset type (Control Center, substation, generation resource) and the specific configuration of the asset. If this approach is used, the intent is for the Responsible Entity to define the electronic boundary such that the low impact BES Cyber System(s) located

at the asset are contained within the “electronic boundary.” This is strictly for determining which routable protocol communications and networks are internal or inside or local to the asset and which are external to or outside the asset.

Alternatively, the Responsible Entity may find the concepts of what is inside and outside to be intuitively obvious for a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) communicating to a low impact BES Cyber System(s) inside the asset. This may be the case when a low impact BES Cyber System(s) is communicating with a Cyber Asset many miles away and a clear and unambiguous demarcation exists. In this case, a Responsible Entity may decide not to identify an “electronic boundary,” but rather to simply leverage the unambiguous asset demarcation to ensure that the electronic access controls are placed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset.

Determining Electronic Access Controls

Once a Responsible Entity has determined that there is routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s), the intent is for the Responsible Entity to document and implement its chosen electronic access control(s). The control(s) are intended to allow only “necessary” inbound and outbound electronic access as determined by the Responsible Entity. However the Responsible Entity chooses to document the inbound and outbound access permissions and the need, the intent is that the Responsible Entity is able to explain the reasons for the electronic access permitted. The reasoning for “necessary” inbound and outbound electronic access controls may be documented within the Responsible Entity’s cyber security plan(s), within a comment on an access control list, a database, spreadsheet or other policies or procedures associated with the electronic access controls.

Concept Diagrams

The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the intent is to achieve the security objective of permitting only necessary inbound and outbound electronic access for communication between low impact BES Cyber Systems and Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) using a routable protocol when entering or leaving the asset.

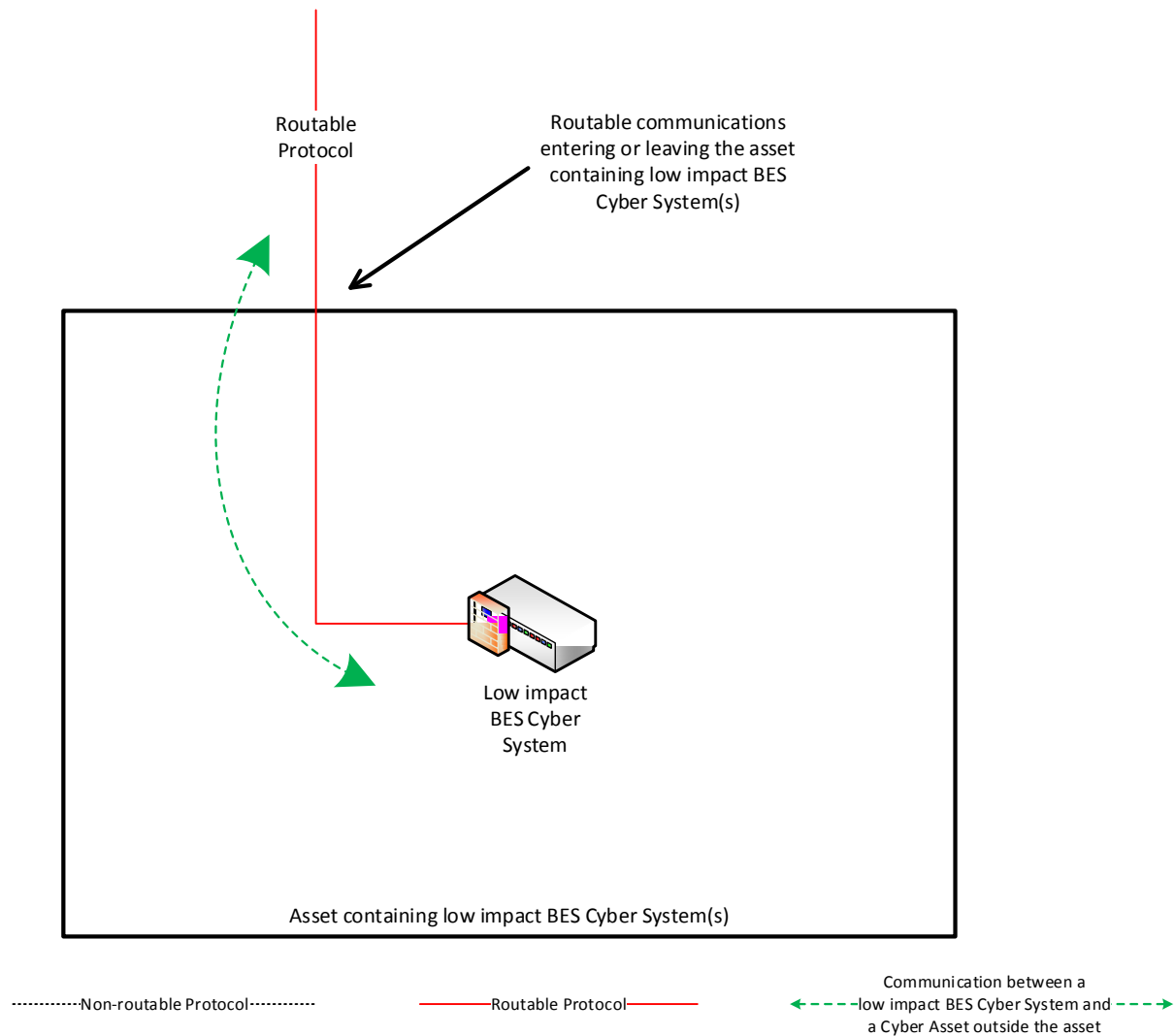
NOTE:

- This is not an exhaustive list of applicable concepts.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.

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Reference Model 1 – Host-based Inbound & Outbound Access Permissions

The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) itself that manages the inbound and outbound electronic access permissions so that only necessary inbound and outbound electronic access is allowed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 1

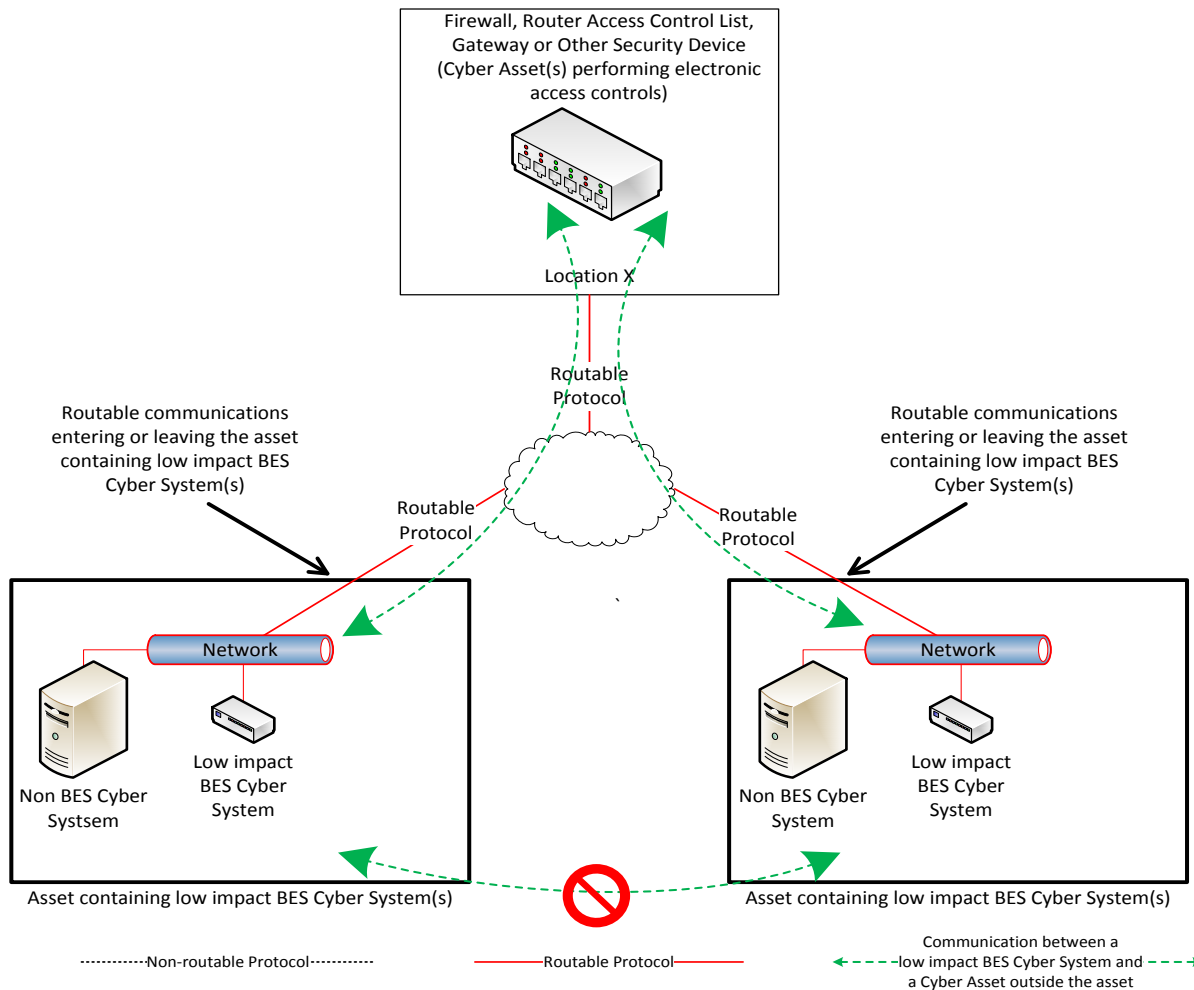
The Responsible Entity may choose to use a security device that permits only necessary inbound and outbound electronic access to the low impact BES Cyber System(s) within the asset containing the low impact BES Cyber System(s). In this example, two low impact BES Cyber Systems are accessed using the routable protocol that is entering or leaving the asset containing the low impact BES Cyber System(s). The IP/Serial converter is continuing the same communications session from the Cyber Asset(s) that are outside the asset to the low impact BES Cyber System(s). The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



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Reference Model 3 – Centralized Network-based Inbound & Outbound Access Permissions

The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be at another asset containing low impact BES Cyber System(s). The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at “Location X” to act as the electronic access control and permit only necessary inbound and outbound routable protocol access between the low impact BES Cyber System(s) and the Cyber Asset(s) outside each asset containing low impact BES Cyber System(s). Care should be taken that electronic access to or between each asset is through the Cyber Asset(s) determined by the Responsible Entity to be performing electronic access controls at the centralized location. When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).

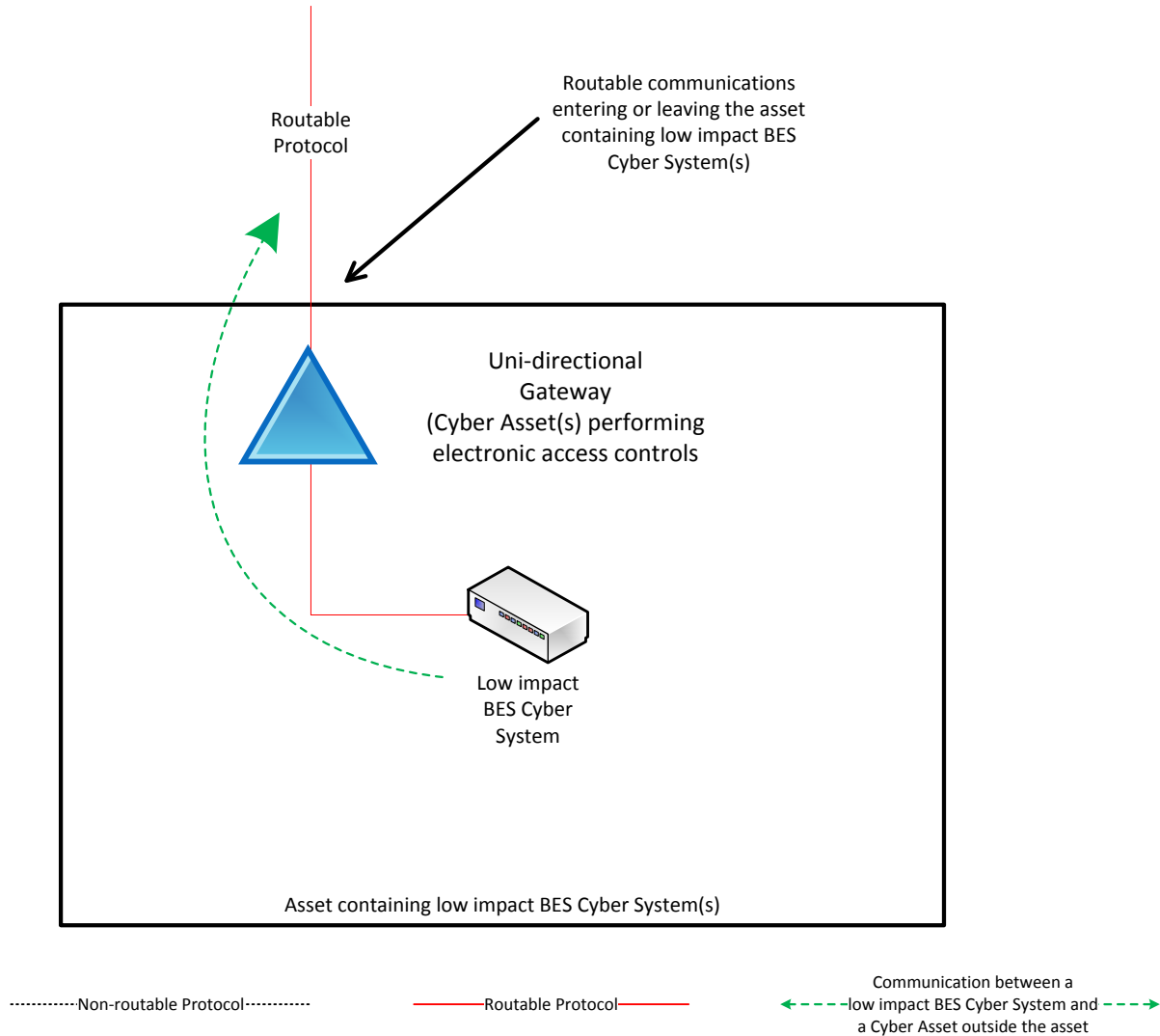


Reference Model 3

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Reference Model 4 – Uni-directional Gateway

The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) using the routable protocol entering the asset due to the implementation of a “one-way” (uni-directional) path for data to flow. The uni-directional gateway is configured to permit only the necessary outbound communications using the routable protocol communication leaving the asset.

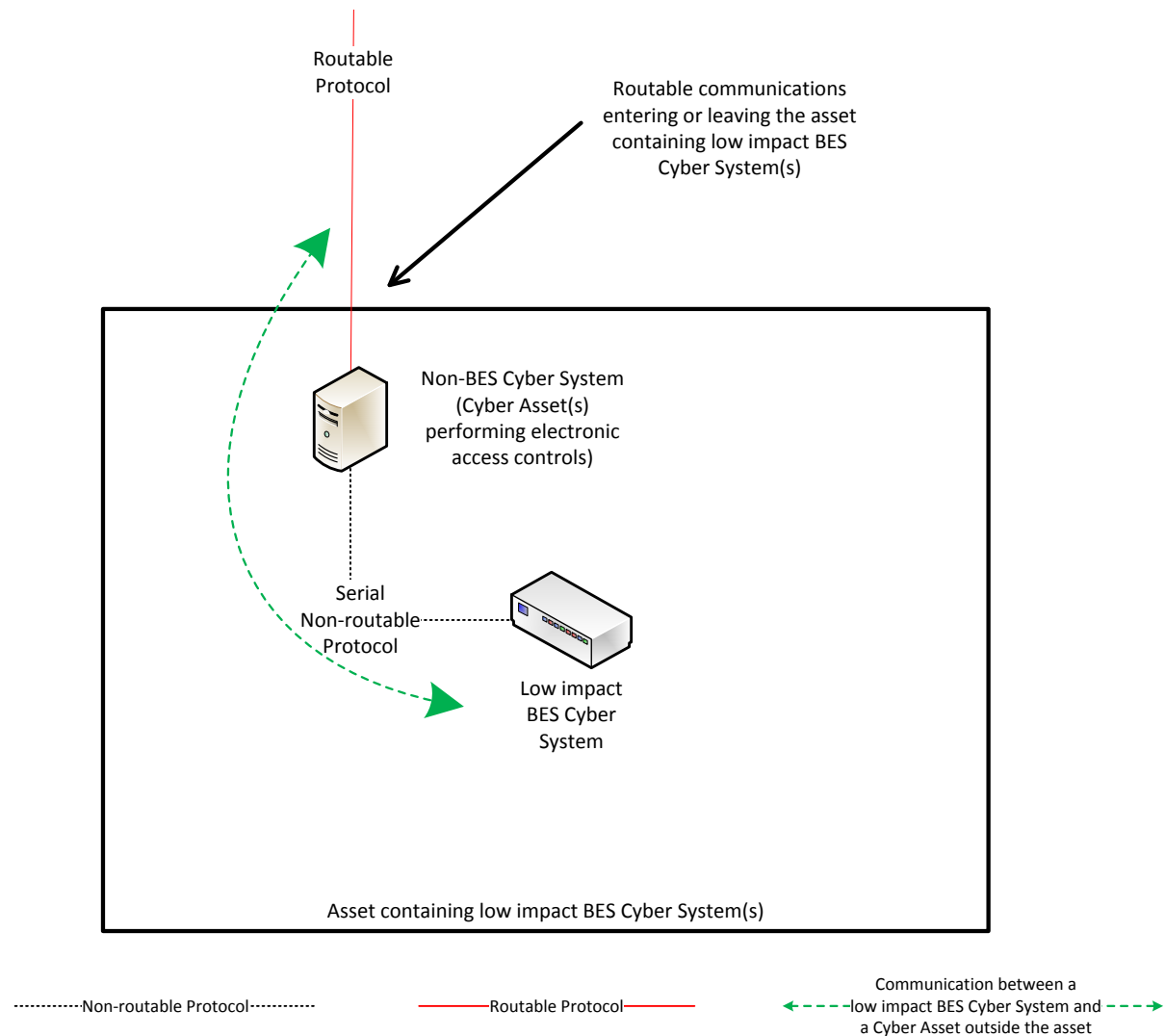


Reference Model 4

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Reference Model 5 – User Authentication

This reference model demonstrates that Responsible Entities have flexibility in choosing electronic access controls so long as the security objective of the requirement is met. The Responsible Entity may choose to utilize a non-BES Cyber Asset located at the asset containing the low impact BES Cyber System that requires authentication for communication from the Cyber Asset(s) outside the asset. This non-BES Cyber System performing the authentication permits only authenticated communication to connect to the low impact BES Cyber System(s), meeting the first half of the security objective to permit only necessary inbound electronic access. Additionally, the non-BES Cyber System performing authentication is configured such that it permits only necessary outbound communication meeting the second half of the security objective. Often, the outbound communications would be controlled in this network architecture by permitting no communication to be initiated from the low impact BES Cyber System. This configuration may be beneficial when the only communication to a device is for user-initiated interactive access.

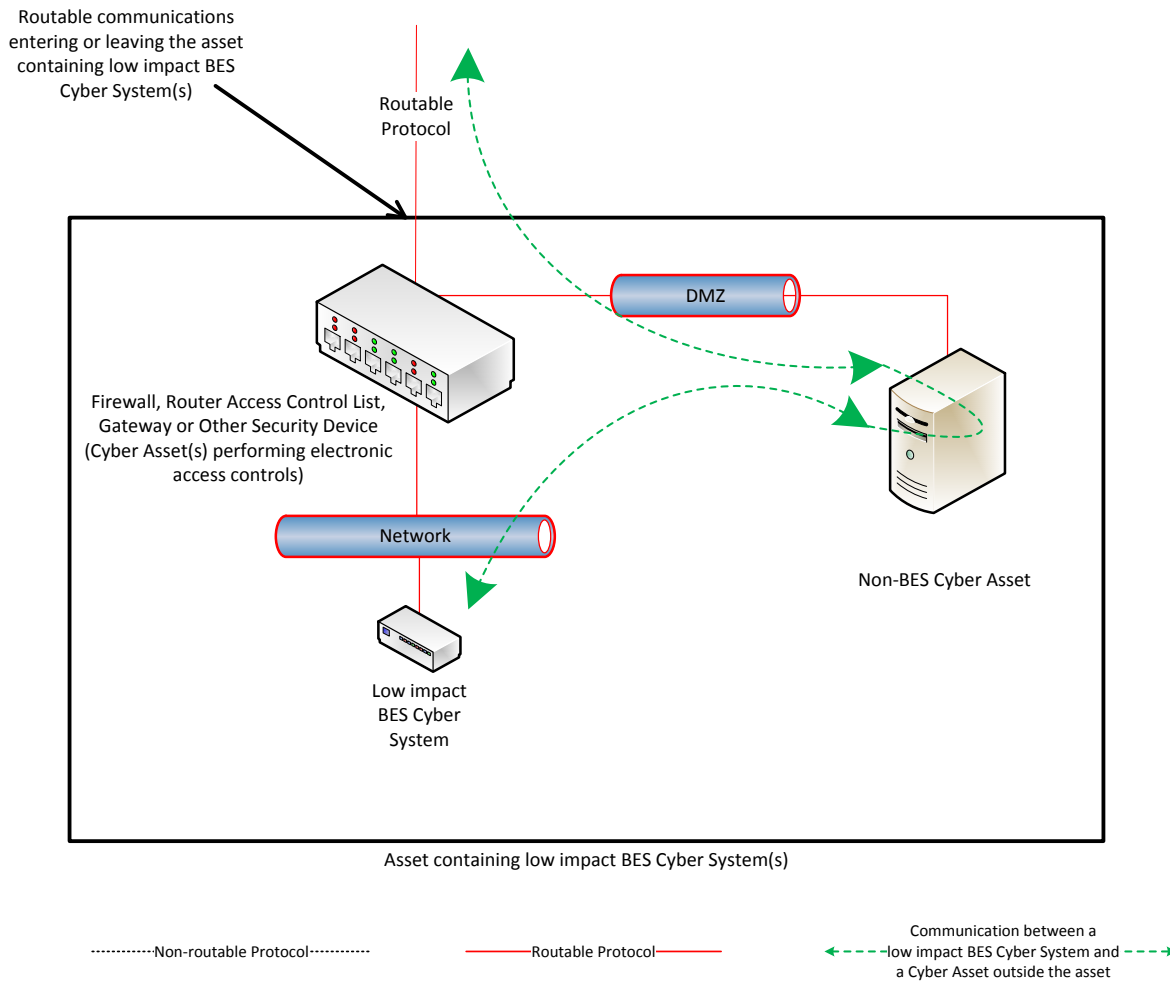


Reference Model 5

CIP-003-7 Supplemental Material

Reference Model 6 – Indirect Access

In implementing its electronic access controls, the Responsible Entity may identify that it has indirect access between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System through a non-BES Cyber Asset located within the asset. This indirect access meets the criteria of having communication between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System. In this reference model, it is intended that the Responsible Entity implement electronic access controls that permit only necessary inbound and outbound electronic access to the low impact BES Cyber System. Consistent with the other reference models provided, the electronic access in this reference model is controlled using the security device that is restricting the communication that is entering or leaving the asset.

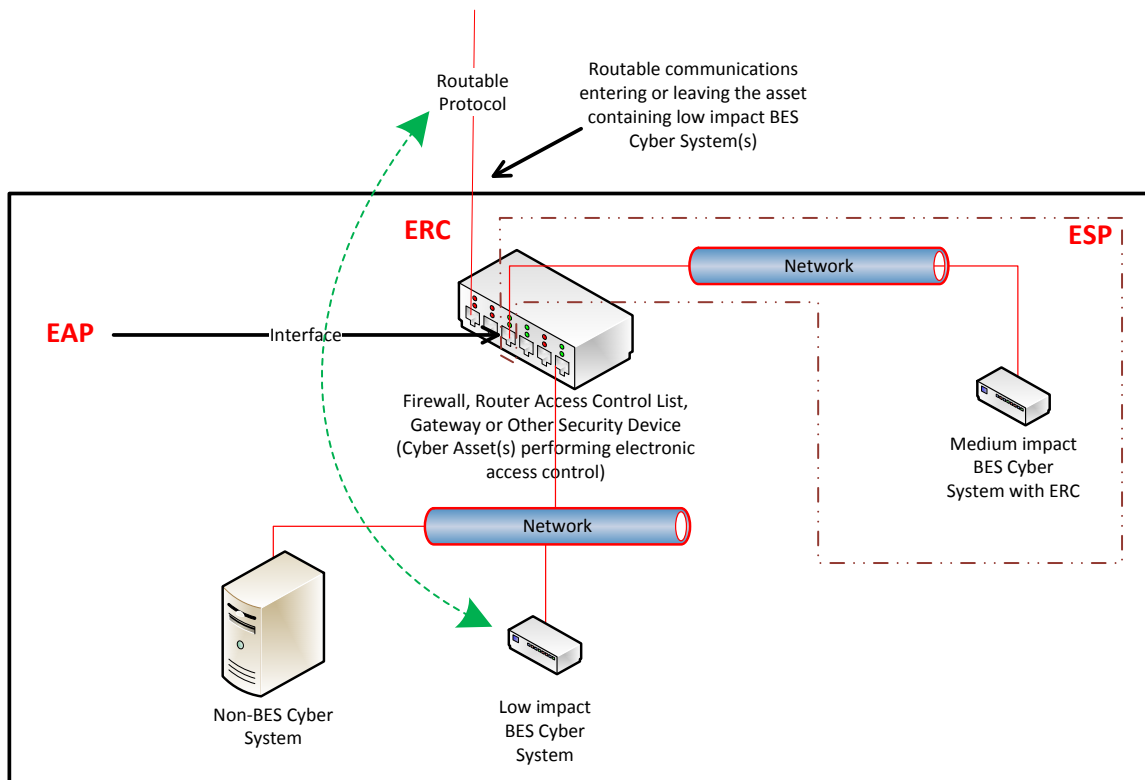


Reference Model 6

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Reference Model 7 – Electronic Access Controls at assets containing low impact BES Cyber Systems and ERC

In this reference model, there is both a routable protocol entering and leaving the asset containing the low impact BES Cyber System(s) that is used by Cyber Asset(s) outside the asset and External Routable Connectivity because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the asset using the routable protocol communications. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) to provide electronic access controls for purposes of CIP-003. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing electronic access controls for an asset containing low impact BES Cyber Systems.



Asset containing low impact BES Cyber System(s) and medium impact BES Cyber System(s)

.....Non-routable Protocol.....

———Routable Protocol———

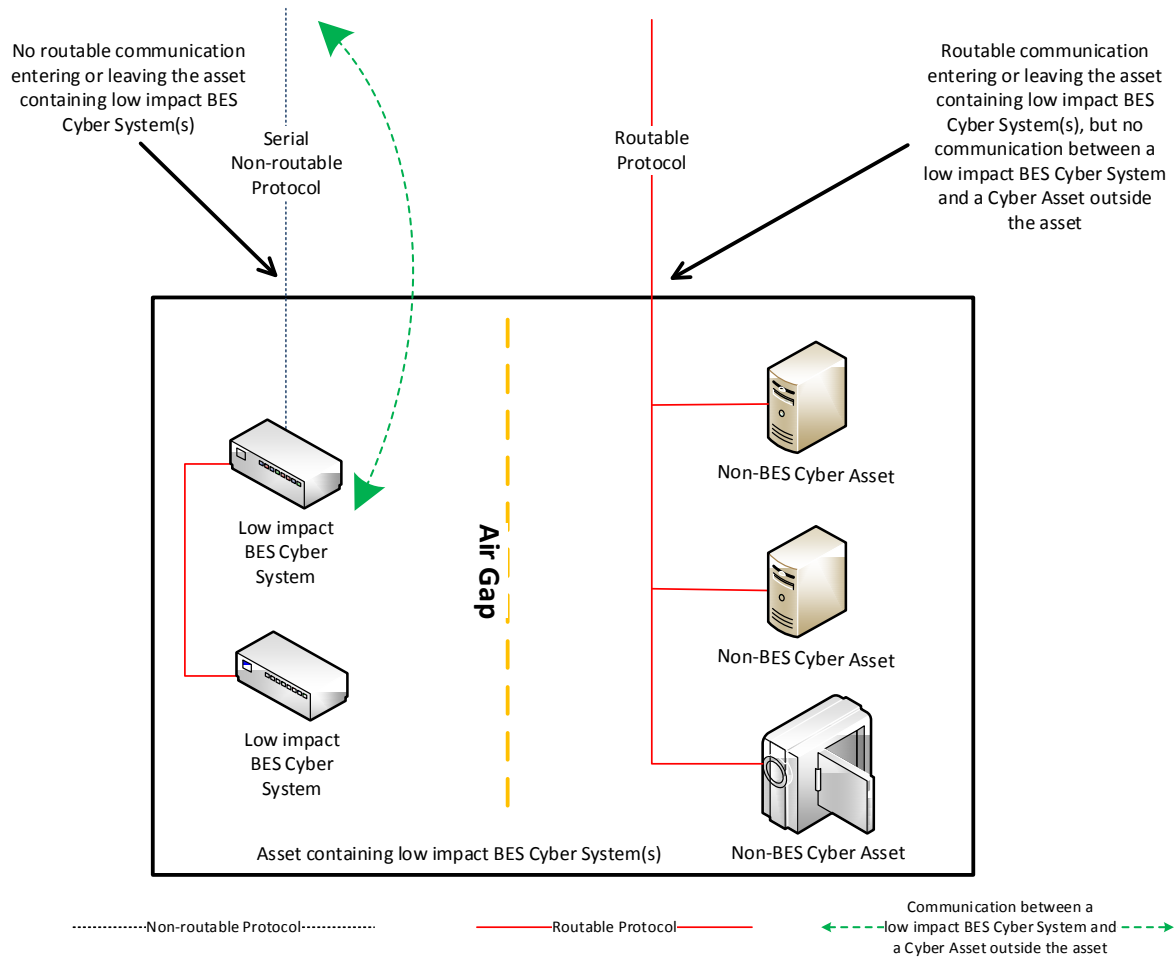
Communication between a
low impact BES Cyber System and
a Cyber Asset outside the asset

Reference Model 7

Reference Model 8 – Physical Isolation and Serial Non-routable Communications – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model demonstrates three concepts:

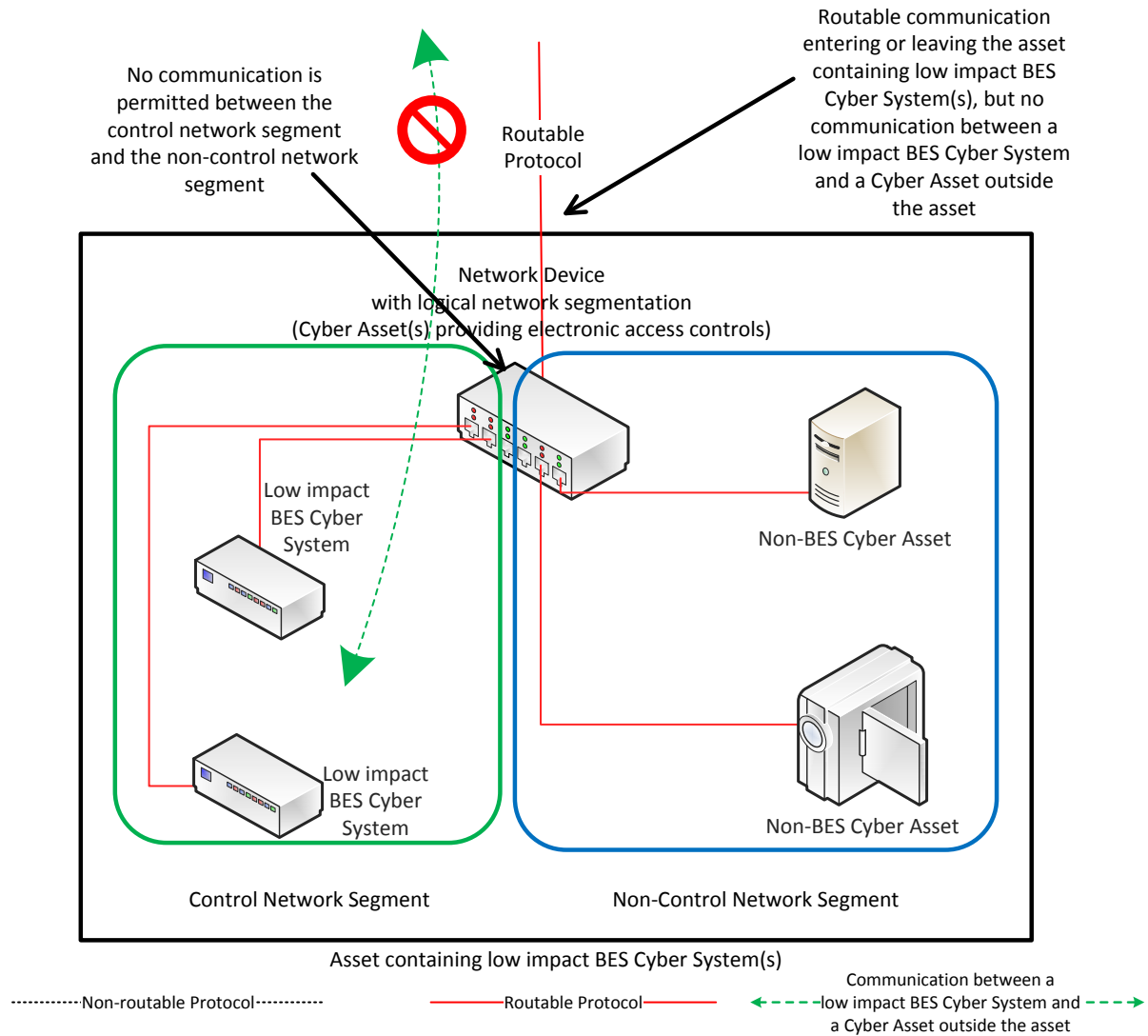
- 1) The physical isolation of the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing the low impact BES Cyber System(s), commonly referred to as an 'air gap', mitigates the need to implement the required electronic access controls;
- 2) The communication to the low impact BES Cyber System from a Cyber Asset outside the asset containing the low impact BES Cyber System(s) using only a serial non-routable protocol where such communication is entering or leaving the asset mitigates the need to implement the required electronic access controls.
- 3) The routable protocol communication between the low impact BES Cyber System(s) and other Cyber Asset(s), such as the second low impact BES Cyber System depicted, may exist without needing to implement the required electronic access controls so long as the routable protocol communications never leaves the asset containing the low impact BES Cyber System(s).



Reference Model 8

Reference Model 9 – Logical Isolation - No Electronic Access Controls Required

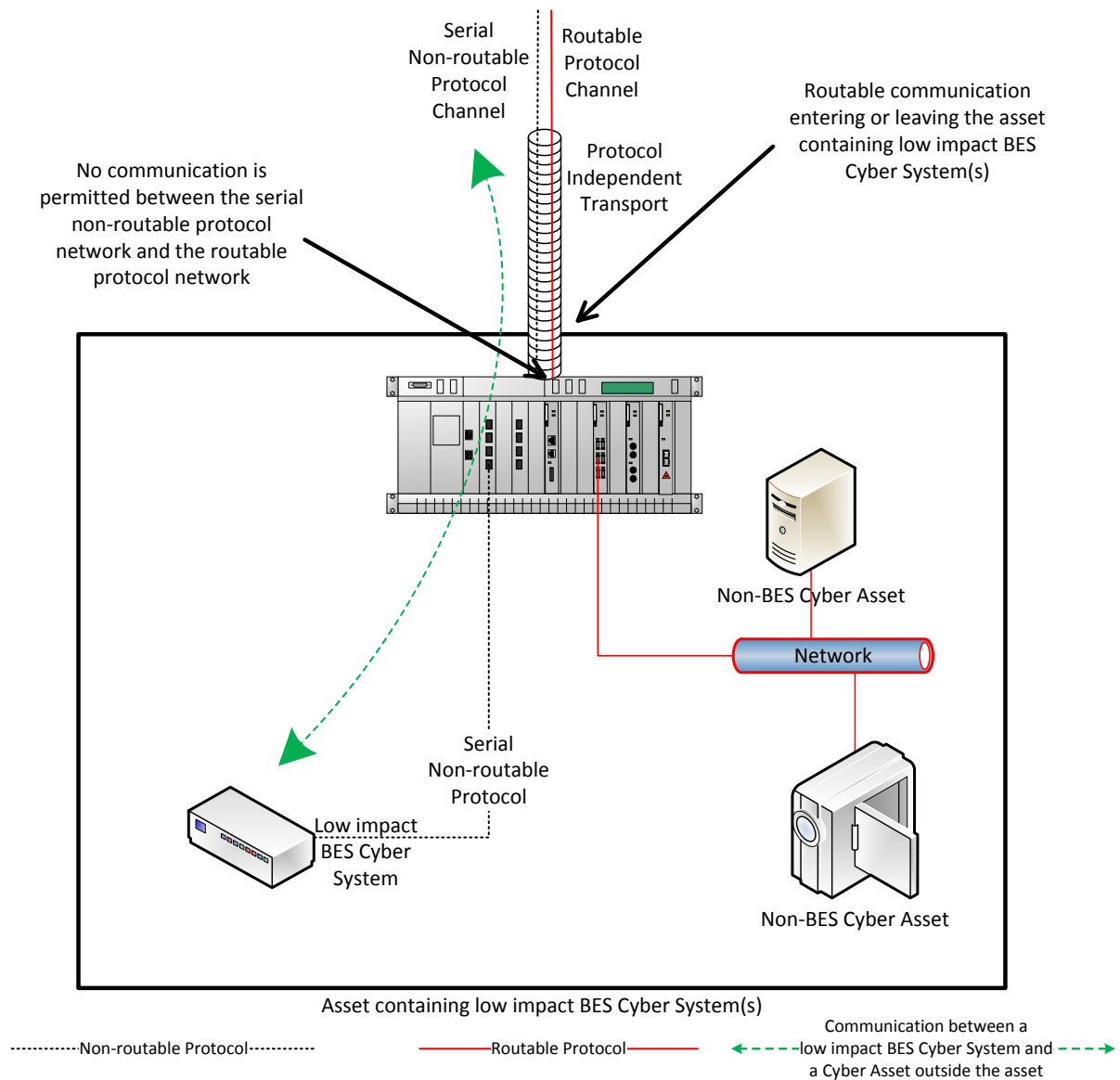
In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. The Responsible Entity has logically isolated the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing low impact BES Cyber System(s). The logical network segmentation in this reference model permits no communication between a low impact BES Cyber System and a Cyber Asset outside the asset. Additionally, no indirect access exists because those non-BES Cyber Assets that are able to communicate outside the asset are strictly prohibited from communicating to the low impact BES Cyber System(s). The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s) and these communications never leave the asset using a routable protocol.



Reference Model 9

Reference Model 10 - Serial Non-routable Communications Traversing an Isolated Channel on a Non-routable Transport Network – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model depicts communication between a low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System over a serial non-routable protocol which is transported across a wide-area network using a protocol independent transport that may carry routable and non-routable communication such as a Time-Division Multiplexing (TDM) network, a Synchronous Optical Network (SONET), or a Multiprotocol Label Switching (MPLS) network. While there is routable protocol communication entering or leaving the asset containing low impact BES Cyber Systems(s) and there is communication between a low impact BES Cyber System and a Cyber Asset outside the asset, the communication between the low impact BES Cyber System and the Cyber Asset outside the asset is not using the routable protocol communication. This model is related to Reference Model 9 in that it relies on logical isolation to prohibit the communication between a low impact BES Cyber System and a Cyber Asset outside the asset from using a routable protocol.



Reference Model 10

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Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

Insufficient Access Controls

Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- A low impact BES Cyber System has a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the external network would not meet the intent of “controlling” inbound and outbound electronic access assuming there was no other host-based firewall or other security devices on the non-BES Cyber Asset.

Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity’s response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, “A malicious act or suspicious event that disrupts, or was an attempt to

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disrupt, the operation of a BES Cyber System.” The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R2, Attachment 1, Section 5 – Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

Most BES Cyber Assets and BES Cyber Systems are isolated from external public or untrusted networks, and therefore Transient Cyber Assets and Removable Media are needed to transport files to and from secure areas to maintain, monitor, or troubleshoot critical systems. Transient Cyber Assets and Removable Media are a potential means for cyber-attack. To protect the BES Cyber Assets and BES Cyber Systems, CIP-003 Requirement R2, Attachment 1, Section 5 requires Responsible Entities to document and implement a plan for how they will mitigate the risk of malicious code introduction to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media. The approach of defining a plan allows the Responsible Entity to document processes that are supportable within its organization and in alignment with its change management processes.

Transient Cyber Assets can be one of many types of devices from a specially-designed device for maintaining equipment in support of the BES to a platform such as a laptop, desktop, or tablet that may interface with or run applications that support BES Cyber Systems and is capable of transmitting executable code to the BES Cyber Asset(s) or BES Cyber System(s). Note: Cyber Assets connected to a BES Cyber System for less than 30 days due to an unplanned removal, such as premature failure, are not intended to be identified as Transient Cyber Assets. Removable Media subject to this requirement include, among others, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Examples of these temporarily connected devices include, but are not limited to:

- Diagnostic test equipment;
- Equipment used for BES Cyber System maintenance; or
- Equipment used for BES Cyber System configuration.

To meet the objective of mitigating risks associated with the introduction of malicious code at low impact BES Cyber Systems, Section 5 specifies the capabilities and possible security methods available to Responsible Entities based upon asset type and ownership.

With the list of options provided in Attachment 1, the entity has the discretion to use the option(s) that is most appropriate. This includes documenting its approach for how and when the entity reviews the Transient Cyber Asset under its control or under the control of parties other than the Responsible Entity. The entity should avoid implementing a security function that jeopardizes reliability by taking actions that would negatively impact the performance or support of the Transient Cyber Asset or BES Cyber Asset.

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Malicious Code Risk Mitigation

The terms “mitigate”, “mitigating”, and “mitigation” are used in Section 5 in Attachment 1 to address the risks posed by malicious code when connecting Transient Cyber Assets and Removable Media to BES Cyber Systems. Mitigation is intended to mean that entities reduce security risks presented by connecting the Transient Cyber Asset or Removable Media. When determining the method(s) to mitigate the introduction of malicious code, it is not intended for entities to perform and document a formal risk assessment associated with the introduction of malicious code.

Per Transient Cyber Asset Capability

As with other CIP standards, the requirements are intended for an entity to use the method(s) that the system is capable of performing. The use of “per Transient Cyber Asset capability” is to eliminate the need for a Technical Feasibility Exception when it is understood that the device cannot use a method(s). For example, for malicious code, many types of appliances are not capable of implementing antivirus software; therefore, because it is not a capability of those types of devices, implementation of the antivirus software would not be required for those devices.

Requirement R2, Attachment 1, Section 5.1 - Transient Cyber Asset(s) Managed by the Responsible Entity

For Transient Cyber Assets and Removable Media that are connected to both low impact and medium/high impact BES Cyber Systems, entities must be aware of the differing levels of requirements and manage these assets under the program that matches the highest impact level to which they will connect.

Section 5.1: Entities are to document and implement their plan(s) to mitigate malicious code through the use of one or more of the protective measures listed, based on the capability of the Transient Cyber Asset.

The Responsible Entity has the flexibility to apply the selected method(s) to meet the objective of mitigating the introductions of malicious code either in an on-going or in an on-demand manner. An example of managing a device in an on-going manner is having the antivirus solution for the device managed as part of an end-point security solution with current signature or pattern updates, regularly scheduled systems scans, etc. In contrast, for devices that are used infrequently and the signatures or patterns are not kept current, the entity may manage those devices in an on-demand manner by requiring an update to the signatures or patterns and a scan of the device before the device is connected to ensure that it is free of malicious code.

Selecting management in an on-going or on-demand manner is not intended to imply that the control has to be verified at every single connection. For example, if the device is managed in an on-demand manner, but will be used to perform maintenance on several BES Cyber Asset(s), the Responsible Entity may choose to document that the Transient Cyber Asset has been updated before being connected as a Transient Cyber Asset for the first use of that maintenance work. The intent is not to require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

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The following is additional discussion of the methods to mitigate the introduction of malicious code.

- Antivirus software, including manual or managed updates of signatures or patterns, provides flexibility to manage Transient Cyber Asset(s) by deploying antivirus or endpoint security tools that maintain a scheduled update of the signatures or patterns. Also, for devices that do not regularly connect to receive scheduled updates, entities may choose to update the signatures or patterns and scan the Transient Cyber Asset prior to connection to ensure no malicious software is present.
- Application whitelisting is a method of authorizing only the applications and processes that are necessary on the Transient Cyber Asset. This reduces the risk that malicious software could execute on the Transient Cyber Asset and impact the BES Cyber Asset or BES Cyber System.
- When using methods other than those listed, entities need to document how the other method(s) meet the objective of mitigating the risk of the introduction of malicious code.

If malicious code is discovered on the Transient Cyber Asset, it must be mitigated prior to connection to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. An entity may choose to not connect the Transient Cyber Asset to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident.

Requirement R2, Attachment 1, Section 5.2 - Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity

Section 5 also recognizes the lack of direct control over Transient Cyber Assets that are managed by parties other than the Responsible Entity. This lack of control, however, does not obviate the Responsible Entity's responsibility to ensure that methods have been deployed to mitigate the introduction of malicious code to low impact BES Cyber System(s) from Transient Cyber Assets it does not manage. Section 5 requires entities to review the other party's security practices with respect to Transient Cyber Assets to help meet the objective of the requirement. The use of "prior to connecting the Transient Cyber Assets" is intended to ensure that the Responsible Entity conducts the review before the first connection of the Transient Cyber Asset to help meet the objective to mitigate the introduction of malicious code. The SDT does not intend for the Responsible Entity to conduct a review for every single connection of that Transient Cyber Asset once the Responsible Entity has established the Transient Cyber Asset is meeting the security objective. The intent is to not require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

To facilitate these controls, Responsible Entities may execute agreements with other parties to provide support services to BES Cyber Systems and BES Cyber Assets that may involve the use of Transient Cyber Assets. Entities may consider using the Department of Energy Cybersecurity Procurement Language for Energy Delivery dated April 2014.¹ Procurement language may unify

¹ <http://www.energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014>

the other party and entity actions supporting the BES Cyber Systems and BES Cyber Assets. CIP program attributes may be considered including roles and responsibilities, access controls, monitoring, logging, vulnerability, and patch management along with incident response and back up recovery may be part of the other party's support. Entities may consider the "General Cybersecurity Procurement Language" and "The Supplier's Life Cycle Security Program" when drafting Master Service Agreements, Contracts, and the CIP program processes and controls.

Section 5.2: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more of the protective measures listed.

- Review the use of antivirus software and signature or pattern levels to ensure that the level is adequate to the Responsible Entity to mitigate the risk of malicious software being introduced to an applicable system.
- Review the antivirus or endpoint security processes of the other party to ensure that their processes are adequate to the Responsible Entity to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of application whitelisting used by the other party to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of live operating systems or software executable only from read-only media to ensure that the media is free from malicious software itself. Entities should review the processes to build the read-only media as well as the media itself.
- Review system hardening practices used by the other party to ensure that unnecessary ports, services, applications, etc. have been disabled or removed. This method intends to reduce the attack surface on the Transient Cyber Asset and reduce the avenues by which malicious software could be introduced.

Requirement R2, Attachment 1, Section 5.3 - Removable Media

Entities have a high level of control for Removable Media that are going to be connected to their BES Cyber Assets.

Section 5.3: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more method(s) to detect malicious code on the Removable Media before it is connected to a BES Cyber Asset. When using the method(s) to detect malicious code, it is expected to occur from a system that is not part of the BES Cyber System to reduce the risk of propagating malicious code into the BES Cyber System network or onto one of the BES Cyber Assets. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident. Frequency and timing of the methods used to detect malicious code were intentionally excluded from the requirement because there are multiple timing scenarios that

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can be incorporated into a plan to mitigate the risk of malicious code. The SDT does not intend to obligate a Responsible Entity to conduct a review for every single connection of Removable Media, but rather to implement its plan(s) in a manner that protects all BES Cyber Systems where Removable Media may be used. The intent is to not require a log documenting each connection of Removable Media to a BES Cyber Asset.

As a method to detect malicious code, entities may choose to use Removable Media with on-board malicious code detection tools. For these tools, the Removable Media are still used in conjunction with a Cyber Asset to perform the detection. For Section 5.3.1, the Cyber Asset used to perform the malicious code detection must be outside of the BES Cyber System.

Requirement R3:

The intent of CIP-003-7, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-7, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity significant flexibility to adapt this requirement to its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-to-date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

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Rationale:

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

Rationale for Requirement R1:

One or more security policies enable effective implementation of the requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to a Responsible Entity's BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the requirements.

Annual review and approval of the cyber security policies ensures that the policies are kept-up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers five subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; (4) Cyber Security Incident response; and (5) Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for Modifications to Sections 2 and 3 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 73 of FERC Order No. 822, the Commission directed NERC to modify "...the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6...to provide needed clarity to the definition

and eliminate ambiguity surrounding the term ‘direct’ as it is used in the proposed definition...within one year of the effective date of this Final Rule.”

The revisions to Section 3 incorporate select language from the LERC definition into Attachment 1 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). This change requires the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the following exclusion language (previously in the definition of LERC) contained in romanette (iii): “not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)”.

The revisions to Section 2 of Attachment 1 complement the revisions to Section 3; consequently, the requirement now mandates the Responsible Entity control physical access to “the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.” The focus on electronic access controls rather than on the Low Impact BES Cyber System Electronic Access Points (LEAPs) eliminates the need for LEAPs.

Given these revisions to Sections 2 and 3, the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP) will be retired.

Rationale for Section 5 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 32 of FERC Order No. 822, the Commission directed NERC to “...provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability.” Transient devices are potential vehicles for introducing malicious code into low impact BES Cyber Systems. Section 5 of Attachment 1 is intended to mitigate the risk of malware propagation to the BES through low impact BES Cyber Systems by requiring entities to develop and implement one or more plan(s) to address the risk. The cyber security plan(s) along with the cyber security policies required under Requirement R1, Part 1.2, provide a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Rationale for Requirement R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the CIP Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-4
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as “Responsible Entity.”
 - 4.1.1. Reliability Coordinator
 - 4.1.2. Balancing Authority
 - 4.1.3. Transmission Owner
 - 4.1.4. Transmission Operator
 - 4.1.5. Generator Owner
 - 4.1.6. Generator Operator
 - 4.1.7. Distribution Provider
5. ~~**Effective Date:** See the Implementation Plan for EOP-004-4.~~

B. Requirements and Measures

- R1. Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-4 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1. Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-4 Attachment 1 and in accordance with the entity responsible for reporting.
- R2. Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity’s next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

- M2.** Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-004-4 Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

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

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

1.3. 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.	The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.
R2.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable.	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal. OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the

EOP-004-4 – Event Reporting

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the end of the next business day, as applicable.	the end of the next business day, as applicable.	end of the next business day, as applicable. OR The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1.

D. Regional Variances

None.

E. Associated Documents

[Link](#) to the Implementation Plan and other important associated documents.

EOP-004-4 – Event Reporting

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: “Any medium that allows two or more individuals to interact, consult, or exchange information.” The NERC Glossary of Terms defines Alternative Interpersonal Communication as: “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.”

Complete loss of monitoring or control capability at a BES control center: Language revisions to: “Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more” provides clarity to the “Threshold for Reporting” and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency.

EOP-004-4 – Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of its Facility	TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. It is not necessary to report theft unless it degrades normal operation of its Facility.
Physical threats to its Facility	TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at its Facility.
Physical threats to its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at its BES control center.
Public appeal for load reduction resulting from a BES Emergency	BA	Public appeal for load reduction to maintain continuity of the BES.
System-wide voltage reduction resulting from a BES Emergency	TOP	System-wide voltage reduction of 3% or more.
Firm load shedding resulting from a BES Emergency	Initiating RC, BA, or TOP	Firm load shedding $\geq$ 100 MW (manual or automatic).

EOP-004-4 – Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
BES Emergency resulting in voltage deviation on a Facility	TOP	A voltage deviation of $\geq$ 10% of nominal voltage sustained for $\geq$ 15 continuous minutes.
Uncontrolled loss of firm load resulting from a BES Emergency	BA, TOP, DP	Uncontrolled loss of firm load for $\geq$ 15 minutes from a single incident: $\geq$ 300 MW for entities with previous year's peak demand $\geq$ 3,000 MW OR $\geq$ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island $\geq$ 100 MW
Generation loss	BA	Total generation loss, within one minute, of: $\geq$ 2,000 MW in the Eastern, Western, or Quebec Interconnection OR $\geq$ 1,400 MW in the ERCOT Interconnection Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.

EOP-004-4 – Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing).
Unplanned evacuation of its BES control center	RC, BA, TOP	Unplanned evacuation from its BES control center facility for 30 continuous minutes or more.
Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center	RC, BA, TOP	Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more.
Complete loss of monitoring or control capability at its staffed BES control center	RC, BA, TOP	Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form		
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "... (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."		
Task	Comments	
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):	
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:	
3.	Did the event originate in your system?	Yes ☐ No ☐ Unknown ☐
4.	Event Identification and Description: (Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical threat to its Facility ☐ Physical threat to its BES control center ☐ BES Emergency: ☐ firm load shedding ☐ public appeal for load reduction ☐ System-wide voltage reduction ☐ voltage deviation on a Facility ☐ uncontrolled loss of firm load ☐ System separation (islanding) ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss ☐ Unplanned evacuation of its BES control center ☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center ☐ Complete loss of monitoring or control capability at its staffed BES control center	
		Written description (optional):

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS
3	November 19, 2015	FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.	
4	February 9, 2017	Adopted by the NERC Board of Trustees	Revised
4	January 18, 2018	FERC order issued approving EOP-004-4. Docket No. RM17-12-000	

Guideline and Technical Basis

Multiple Reports for a Single Organization

For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Law Enforcement Reporting

The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

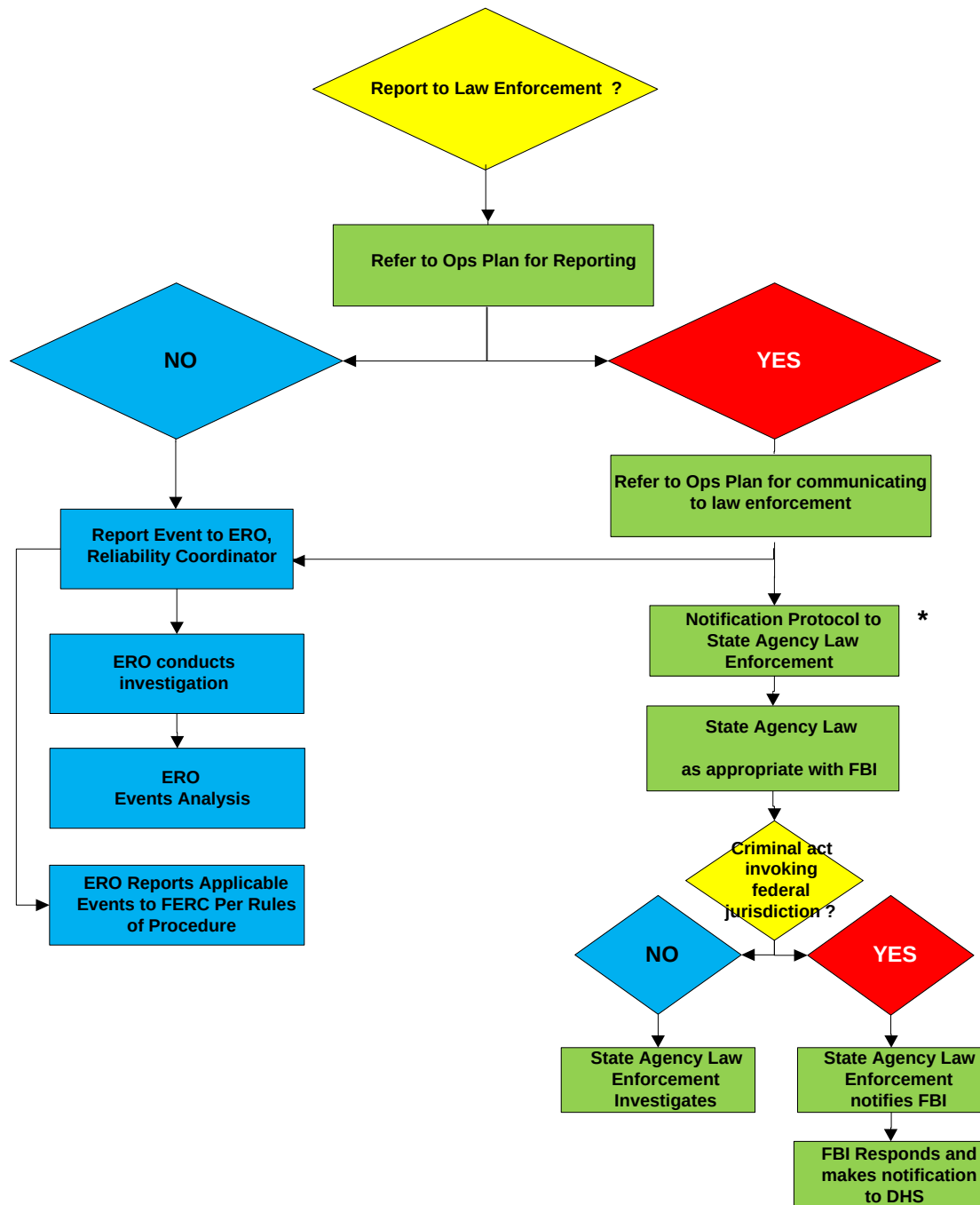
Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-3
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Transmission Operators
 - 4.1.2. Generator Operators
 - 4.1.3. Transmission Owners identified in the Transmission Operators restoration plan
 - 4.1.4. Distribution Providers identified in the Transmission Operators restoration plan
5. ~~**Effective Date:** See the Implementation Plan for EOP-005-3.~~
6. **Standard-Only Definition:** None

B. Requirements and Measures

- R1. Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High]* *[Time Horizon = Operations Planning, Real-time Operations]*
 - 1.1. Strategies for System restoration that are coordinated with its Reliability Coordinator's high level strategy for restoring the Interconnection.
 - 1.2. A description of how all Agreements or mutually-agreed upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.
 - 1.3. Procedures for restoring interconnections with other Transmission Operators under the direction of its Reliability Coordinator.
 - 1.4. Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

- 1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.
- 1.6. Identification of acceptable operating voltage and frequency limits during restoration.
- 1.7. Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.
- 1.8. Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.
- 1.9. Operating Processes for transferring operations back to the Balancing Authority in accordance with its Reliability Coordinator's criteria.
- M1.** Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.
- R2.** Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M2.** Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.
- R3.** Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually-agreed, predetermined schedule. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M3.** Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.
- R4.** Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- 4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.
- 4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.
- M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has submitted the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.
- R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*
- M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.
- R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*
 - 6.1. The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.
 - 6.2. The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.
 - 6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.
- M6. Each Transmission Operator shall have documentation, such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.
- R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
 - 7.1. The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.
 - 7.2. A list of required tests including:

- 7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.
 - 7.2.2. The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.
- 7.3. The minimum duration of each of the required tests.
- M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.
- R8. Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
 - 8.1. System restoration plan including coordination with its Reliability Coordinator and Generator Operators included in the restoration plan.
 - 8.2. Restoration priorities.
 - 8.3. Building of cranking paths.
 - 8.4. Synchronizing (re-energized sections of the System).
 - 8.5. Transition of Demand and resource balance within its area to the Balancing Authority.
- M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.
- R9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

- R10.** Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M10.** Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.
- R11.** Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M11.** Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.
- R12.** Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M12.** Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.
- R13.** Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M13.** Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.
- R14.** Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- 14.1.** Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.
- 14.2.** Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

- M14.** Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.
- R15.** Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- 15.1.** System restoration plan including coordination with the Transmission Operator
- 15.2.** The procedures documented in Requirement R12
- M15.** Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.
- R16.** Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M16.** Each Generator Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity

"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.

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

- Approved restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator's annually-reviewed restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.
- Submission of a revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current restoration plan approved by its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement R7, Measure M7.
- Training program materials or descriptions for three calendar years for Requirement R8, Measure M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R10, Measure M10.

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

- Training program materials or descriptions and training records for three calendar years for Requirement R9, Measure M9.

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

The Transmission Operator and Generator Operator with a Blackstart Resource 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:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in effect since its last compliance audit for Requirement R11, Measure M11.

The Generator Operator with a Blackstart Resource 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:

- Current documentation and any documentation in effect since its last compliance audit on procedures to start each Blackstart Resource and for energizing a bus for Requirement R12, Measure M12.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement R13, Measure M13.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement R14, Measure M14.
- Training program materials and training records for three calendar years for Requirement R15, Measure M15.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

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

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement R16, Measure M16.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last compliance audit records and all requested and submitted subsequent compliance 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.	The Transmission Operator has an approved plan but failed to comply with one of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with two of the requirement parts within Requirement R1.	The Transmission Operator has an approved plan but failed to comply with three or more of the requirement parts within Requirement R1.	The Transmission Operator does not have an approved restoration plan. OR The Transmission Operator has an approved restoration plan, but failed to implement the applicable requirement parts within Requirement R1.
R2.	The Transmission Operator failed to provide one of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide two of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide three of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.	The Transmission Operator failed to provide four or more of the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan. OR Transmission Operator failed to provide at least half of the entities identified in its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date.
R3.	The Transmission Operator submitted the reviewed restoration plan within 30 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 60 and less than or equal to 90 calendar days after the mutually-agreed, predetermined schedule.	The Transmission Operator submitted the reviewed restoration plan more than 90 calendar days after the mutually-agreed, predetermined schedule.
R4.	The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator has failed to submit its revised restoration plan to its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator prior

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				to a planned permanent BES modification.
R5.	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary and backup control rooms prior to its effective date.
R6.	The Transmission Operator performed the verification within the required timeframe but did not comply with one of the requirement parts.	The Transmission Operator performed the verification within the required timeframe but did not comply with two of the requirement parts.	The Transmission Operator performed the verification but did not complete it within the required time frame.	The Transmission Operator did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the requirement parts.
R7.	N/A	N/A	N/A	The Transmission Operator's Blackstart Resource testing requirements do not address

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				one or more of the requirement parts of Requirement R7.
R8.	The Transmission Operator's training does not address one of the requirement parts of Requirement R8.	The Transmission Operator's training does not address two of the requirement parts of Requirement R8.	The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.	The Transmission Operator has not included System restoration training in its operations training program.
R9.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.	The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.
R10.	N/A	N/A	N/A	The Transmission Operator has failed to comply with a request for its participation from its Reliability Coordinator.
R11.	N/A	The Transmission Operator and Generator Operator	N/A	The Transmission Operator and Generator Operator

EOP-005-3 – System Restoration from Blackstart Resources

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually-agreed upon procedures or protocols.		with a Blackstart resource do not have a written Blackstart Resource Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R13.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 96 hours.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R14.	The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.	The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.
R15.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.	The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.
R16.	N/A	N/A	N/A	The Generator Operator failed to participate in its Reliability Coordinator's

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				restoration drills, exercises, or simulations as requested by its Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

[Link](#) to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	May 2, 2007	Approved by the Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements. Updated Measures and Compliance to match new requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7, 2013	R3.1 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	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
3	February 9, 2017	Adopted by the NERC Board of Trustees	Revised

Rationale

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: "... that would change the implementation of its restoration plan" appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that "90 calendar days" is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between "System modifications" for unplanned changes and "BES modifications" for planned changes has been seen as confusing to some Responsible Entities.

The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to submit a revised restoration plan to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

Rationale for Requirement R9: The intent of "unique tasks" are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-3
3. **Purpose:** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Reliability Coordinators
5. ~~**Proposed Effective Date:** See the Implementation Plan for EOP-006-3.~~
6. **Standard-Only Definition:** None

B. Requirements and Measures

- R1. Each Reliability Coordinator shall develop and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*
 - 1.1. A description of the high-level strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.
 - 1.2. Criteria and conditions for re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.
 - 1.3. Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event.
 - 1.4. Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.
 - 1.5. Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability

Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

- 1.6. Criteria for transferring operations and authority back to the Balancing Authority.
- M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.
- R2. The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*
- M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.
- R3. Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.
- R4. Each Reliability Coordinator shall review its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
 - 4.1. If a Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved within 30 calendar days of receipt of written notification.
- M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.
- R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
 - 5.1. The Reliability Coordinator shall determine whether the Transmission Operator's restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its

Reliability Coordinator Area. The Reliability Coordinator shall provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

- M5.** Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.
- R6.** Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the effective date. *[Violation Risk Factor = Lower]* *[Time Horizon = Operations Planning]*
- M6.** Each Reliability Coordinator shall have documentation such as electronic receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the effective date in accordance with Requirement R6.
- R7.** Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators. This training program shall address the following: *[Violation Risk Factor = Medium]* *[Time Horizon = Operations Planning]*
 - 7.1.** The coordination role of the Reliability Coordinator; and
 - 7.2.** Re-establishing the Interconnection.
- M7.** Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.
- R8.** Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. *[Violation Risk Factor = Medium]* *[Time Horizon = Operations Planning]*
 - 8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.
- M8.** Each Reliability Coordinator shall have evidence, such as dated electronic documents, that it conducted two System restoration drills, exercises, or simulations per calendar year in accordance with Requirement R8. And each Reliability Coordinator shall have

evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

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.

- The current restoration plan and any restoration plans in effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Its reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- Actual training program materials or descriptions for three calendar years for Requirements R7, Measure M7.

- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R8, Measure M8.

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

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

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.	The Reliability Coordinator failed to include one requirement part of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include two requirement parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include three of the requirements parts of Requirement R1 within its restoration plan.	The Reliability Coordinator failed to include four or more of the requirement parts within its restoration plan. OR The Reliability Coordinator had a restoration plan, but failed to implement it.
R2.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to entities identified in Requirement R2 but was 120 calendar days or more late.
R3.	N/A	N/A	N/A	The Reliability Coordinator did not review its restoration plan within 13 calendar months of the last review.

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.	The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.	The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.
R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, with stated reasons for disapproval, from its Transmission Operators and neighboring Reliability Coordinators for more than 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt	The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.	approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.
R6.	N/A	N/A	The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.	The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the effective date.
R7.	N/A	N/A	The Reliability Coordinator included the annual System restoration training within its operations training program,	The Reliability Coordinator did not include the annual System restoration training

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			but did not address both of the requirement parts.	within its operations training program.
R8.	N/A	The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year. OR The Reliability Coordinator did not request each applicable Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation at least once every two calendar years.	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

D. Regional Variances

None.

E. Associated Documents

[Link](#) to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	Nov. 1, 2006	Adopted by Board of Trustees	Revised
2		Revisions pursuant to Project 2006-03	Updated Measures and Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval.	
3	February 9, 2017	Adopted by the NERC Board of Trustees	Revised
3	January 18, 2018	FERC order issued approving EOP-006-3. Docket No. RM17-12-000.	

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Reliability Coordinator
 - 4.1.2. Transmission Operator
 - 4.1.3. Balancing Authority
5. ~~**Effective Date:** See the Implementation Plan for EOP 008 2.~~
6. **Standard-Only Definition:** None

B. Requirements and Measures

- R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
 - 1.1. The location and method of implementation for providing backup functionality.
 - 1.2. A summary description of the elements required to support the backup functionality. These elements shall include:
 - 1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.
 - 1.2.2. Data exchange capabilities.
 - 1.2.3. Interpersonal Communications.
 - 1.2.4. Power source(s).
 - 1.2.5. Physical and cyber security.
 - 1.3. An Operating Process for keeping the backup functionality consistent with the primary control center.
 - 1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.
 - 1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.

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- 1.6.** An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include:
- 1.6.1.** A list of all entities to notify when there is a change in operating locations.
 - 1.6.2.** Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.
 - 1.6.3.** Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.
- M1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.
- R2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*
- M2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.
- R3.** Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*
- Planned outages of the primary or backup facilities of two weeks or less
 - Unplanned outages of the primary or backup facilities
- M3.** Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.
- R4.** Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality

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location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality. To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

- M4.** Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.
- R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- 5.1.** An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.
- M5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.
- R6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M6.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.
- R7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- 7.1.** The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.
- 7.2.** The backup functionality for a minimum of two continuous hours.

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- M7.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.
- R8.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M8.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality 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 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 Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.
- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity’s control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it’s backup functionality (provided either through a facility or contracted services staffed by applicable certified operators

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when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality in accordance with Measurement M4.

- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in effect Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and the previous calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality would last for more than six calendar months shall retain evidence for the current in effect document and any such documents in effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

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.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six parts (Requirement R1, Parts 1.1 through 1.6) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality.
R4.	N/A	N/A	N/A	The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's and Transmission Operator's

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				primary control center functionality.
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted an annual test of	The responsible entity conducted an annual test of	The responsible entity conducted an annual test of	The responsible entity did not conduct an annual test

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	its Operating Plan for backup functionality, but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more than or equal to 0.5 continuous hours.	of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional

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R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

D. Regional Variances

None.

E. Associated Documents

[Link](#) to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	2009 - 2010	Project 2006-04: Revisions	Major re-write to accommodate changes noted in project file
1	August 5, 2010	Project 2006-04: Adopted by the Board	
1	April 21, 2011	Project 2006-04: FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	Project 2006-04: Updated VRFs and VSLs based on June 24, 2013 approval	
2	July 9, 2017	Adopted by the NERC Board of Trustees	Revised
2	January 18, 2018	FERC order issued approving EOP-008-2. Docket No. RM17-12-000.	

Rationale

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing "data communications" in Requirement R1, Part 1.2.2 for the following reasons:

COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data.

The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

A. Introduction

- 1. Title:** Transmission Maintenance
- 2. Number:** FAC-501-WECC-2
- 3. Purpose:** To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.
- 4. Applicability**
 - 4.1 Transmission Owners that maintain the transmission paths in Attachment B.
- ~~**5. Effective Date:** The first day of the first quarter following applicable regulatory approval.~~

B. Requirements and Measures

- R1.** Each Transmission Owner shall have a TMIP that includes, at a minimum, each of the items listed in Attachment A, Transmission Maintenance and Inspection Plan Content. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M1.** Each Transmission Owner will have evidence that it has a TMIP detailing each of the items listed in Attachment A, as required in Requirement R1.
- R2.** Each Transmission Owner shall annually update its TMIP to reflect all changes to its TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M2.** Each Transmission Owner will have evidence that it annually updated its TMIP, as required in Requirement R2. When an annual update shows that no changes are required to the TMIP, evidence may include but is not limited to, attestation that the update was performed but showed that no changes were required.
- R3.** Each Transmission Owner shall adhere to its TMIP. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M3.** Each Transmission Owner will have evidence that it adhered to its TMIP, as required in Requirement R3. Evidence may include, but is not limited to:
 - 1.1** The date(s) the patrol, inspection or maintenance was performed;
 - 1.2** The transmission Facility or Element on which the maintenance was performed;
 - 1.3** A description of the inspection results or maintenance performed.

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.

- The Transmission Owners listed in section 4.1 shall keep data or evidence of Requirements 1-3 for three calendar years, or since the last audit, whichever is longer.
- 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.	The Transmission Owner's TMIP did not include one of the items listed in Attachment A, as required in Requirement R1.	The Transmission Owner's TMIP did not include two of the items listed in Attachment A, as required in Requirement R1.	The Transmission Owner's TMIP did not include three of the items listed in Attachment A, as required in Requirement R1.	The Transmission Owner's TMIP did not include four or more of the items listed in Attachment A, as required in Requirement R1.
R2.	The Transmission Owner did not annually update its TMIP (within the 365 days following the last review), as required by R2.	The Transmission Owner did not update its TMIP within the last one year and 1 day (within the 366 days following the last review), as required by R2.	The Transmission Owner did not update its TMIP within the last two years and 1 day (within the 731 days following the last review), as required by R2.	The Transmission Owner did not update its TMIP within the last three years and 1 day (within the 1095 days following the last review), as required by R2.
R3.	The Transmission Owner failed to adhere to: 1) one transmission line maintenance item, or 2) one station maintenance item, as contained in its TMIP, as required in R3.	The Transmission Owner failed to adhere to: 1) two transmission line maintenance items; or, 2) two station maintenance items; or 3) any combination of two items taken from the above list, for items contained in its TMIP, as required in R3.	The Transmission Owner failed to adhere to: 1) three transmission line maintenance items; or, 2) three station maintenance items; or 3) any combination of three items taken from the above list, for items contained in its TMIP, as required in R3.	The Transmission Owner failed to adhere to: 1) four or more transmission line maintenance items; or, 2) four or more station maintenance items; or, 3) any combination of four or more items taken from the above list, for items contained in its TMIP, as required in R3.

D. Regional Variances

None.

E. Associated Documents

None

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

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-005-1	
1	October 29, 2008	NERC BOT conditional approval	
1	April 21, 2011	FERC Approved in Order 751	
2	July 1, 2017	Approved by the WECC Board of Directors.	1) Conformed to newest NERC template and drafting conventions, 2) eliminated URLs, 3) clarified Attachment A, and Measure M3.
2	February 8, 2018	Approved by the NERC Board of Trustees.	

**Attachment A
Transmission Maintenance and Inspection Plan Content**

The TMIP shall include, at a minimum, each of the following details:

1. Facilities

A list of Facilities (e.g., transmission lines, transformers, etc.) and Elements (e.g. circuit breaker, bus section, etc.) that comprise each transmission path(s) identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System.

2. Maintenance Methodology

A description of the maintenance methodology used for the Facility, transmission line, or station included in the TMIP.

The TMIP maintenance methodology may be any one of the following or any combination thereof, but must include at least one of the following:

- Performance-based
- Time-based
- Condition based

3. Periodicity

A specification of the periodicity that the described maintenance will occur, or under what circumstances it occurs.

4. Transmission Line Maintenance

A description of each of the following for the transmission line(s) included in the TMIP:

- a. Inspection requirements
- b. Patrol requirements
- c. Tower and wood pole structure management

5. Station Maintenance

A description of each of the following for each station included in the TMIP:

- a. Inspection requirements
- b. Equipment maintenance for each of the following:
 1. Circuit breakers
 2. Power transformers (including, but not limited to, phase-shifting transformers)
 3. Reactive devices (including, but not limited to, shunt capacitors, series capacitors, synchronous condensers, shunt reactors, and tertiary reactors)

Attachment B

Major WECC Transfer Paths in the Bulk Electric System

	PATH NAME*	Path Number
1.	Alberta – British Columbia	1
2.	Northwest – British Columbia	3
3.	West of Cascades – North	4
4.	West of Cascades – South	5
5.	West of Hatwai	6
6.	Montana to Northwest	8
7.	Idaho to Northwest	14
8.	South of Los Banos or Midway- Los Banos	15
9.	Idaho – Sierra	16
10.	Borah West	17
11.	Idaho – Montana	18
12.	Bridger West	19
13.	Path C	20
14.	Southwest of Four Corners	22
15.	PG&E – SPP	24
16.	Northern – Southern California	26
17.	Intmntn. Power Project DC Line	27
18.	TOT 1A	30
19.	TOT 2A	31
20.	Pavant – Gonder 230 kV Intermountain – Gonder 230 kV	32
21.	TOT 2B	34
22.	TOT 2C	35
23.	TOT 3	36
24.	TOT 5	39
25.	SDGE – CFE	45
26.	West of Colorado River (WOR)	46
27.	Southern New Mexico (NM1)	47
28.	Northern New Mexico (NM2)	48
29.	East of the Colorado River (EOR)	49
30.	Cholla – Pinnacle Peak	50
31.	Southern Navajo	51
32.	Brownlee East	55
33.	Lugo – Victorville 500 kV	61
34.	Pacific DC Intertie	65
35.	COI	66
36.	North of John Day cutplane	73
37.	Alturas	76
38.	Montana Southeast	80
39.	SCIT**	
40.	COI/PDCI – North of John Day cutplane**	

* For an explanation of terms, path numbers, and definition for the paths refer to WECC's Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC's Path Rating Catalog.

THIS SECTION WILL NOT BE PART OF THE STANDARD BUT IS REQUIRED FOR NERC FILING.

~~Standards Authorization Request (SAR)~~

~~[WECC 0120 FAC 501 WECC 2 Transmission Maintenance SAR](#)~~

~~Approvals Required~~

- ~~• WECC Ballot Pool Pending~~
- ~~• WECC Board of Directors Pending~~
- ~~• NERC Board of Trustees Pending~~
- ~~• FERC Pending~~

~~Applicable Entities~~

~~Transmission Owners that maintain the transmission paths in the most current WECC Major Paths table (Attachment B of the standard)~~

~~Conforming Changes to Other Standards~~

~~None are required.~~

~~Proposed Effective Date~~

~~The first day of the first quarter following regulatory approval~~

~~Justification~~

~~The WECC 0120, FAC 501 WECC 2, Transmission Maintenance Drafting Team (DT) has reviewed NERC Standards, both in effect and those standards that are NERC Board of Trustees approved pending regulatory filing. The DT concluded that the proposed substantive changes pose a minimal burden beyond ordinary and current operations. As such, the short implementation time should impose no undue burden.~~

~~Consideration of Early Compliance~~

~~The DT foresees no negative impacts to reliability in the event of early compliance.~~

~~Retirements~~

~~None~~

A. Introduction

1. **Title:** Operating Personnel Credentials
2. **Number:** PER-003-2
3. **Purpose:** To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Reliability Coordinator
 - 4.1.2. Transmission Operator
 - 4.1.3. Balancing Authority
5. ~~**Effective Date:** See Implementation Plan for standard PER-003-2.~~

B. Requirements and Measures

- R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate ⁽¹⁾⁽²⁾: [*Risk Factor: High*][*Time Horizon: Real-time Operations*]
 - 1.1. Areas of Competency
 - 1.1.1. Resource and demand balancing
 - 1.1.2. Transmission operations
 - 1.1.3. Emergency preparedness and operations
 - 1.1.4. System operations
 - 1.1.5. Protection and control
 - 1.1.6. Voltage and reactive
 - 1.1.7. Interchange scheduling and coordination
 - 1.1.8. Interconnection reliability operations and coordination

¹ Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

² The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M1. Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates ⁽¹⁾⁽²⁾: *[Risk Factor: High][Time Horizon: Real-time Operations]*:

2.1. Areas of Competency

2.1.1. Transmission operations

2.1.2. Emergency preparedness and operations

2.1.3. System operations

2.1.4. Protection and control

2.1.5. Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

¹ Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

² The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

- M2.1** A list of Real-time operating positions.
 - M2.2** A list of System Operators assigned to its Real-time operating positions.
 - M2.3** A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.
 - M2.4** Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.
- R3.** Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates ⁽¹⁾⁽²⁾: [*Risk Factor: High*][*Time Horizon: Real-time Operations*]:
- 3.1. Areas of Competency**
 - 3.1.1.** Resources and demand balancing
 - 3.1.2.** Emergency preparedness and operations
 - 3.1.3.** System operations
 - 3.1.4.** Interchange scheduling and coordination
 - 3.2. Certificates**
 - Reliability Operator
 - Balancing, Interchange and Transmission Operator
 - Balancing and Interchange Operator
- M3.** Each Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:
- M3.1** A list of Real-time operating positions.
 - M3.2** A list of System Operators assigned to its Real-time operating positions.
 - M3.3** A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

¹ Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

² The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

- M3.4** Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

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.

- Each Reliability Coordinator, Transmission Operator and Balancing Authority shall keep data or evidence for three years or since its last compliance audit, whichever time frame is the greatest.

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 Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.
R2.	N/A	N/A	N/A	The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.
R3.	N/A	N/A	N/A	The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.

D. Regional Variances

None.

E. Associated Documents[Implementation Plan](#)**Version History**

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Complete revision under Project 2007-04	Revision
1	February 17, 2011	Adopted by Board of Trustees	
1	September 15, 2011	FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)	
2	May 10, 2018	Added footnote to requirements	Revision
2	May 10, 2018	Adopted by Board of Trustees	Revision
2	November 21, 2018	FERC Letter Order approving PER-003-2. Docket No. RD18-9-000	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Effective Date of Standard: PER-003-2 — Operating Personnel Credentials

United States

Standard	Requirement	Effective Date of Standard	Phased In Implementation Date (if applicable)	Inactive Date
PER-003-2	All	07/01/2019		

Printed On: February 25, 2019, 03:23 PM

A. Introduction

1. **Title:** Specific Training for Personnel
2. **Number:** PER-006-1
3. **Purpose:** To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Generator Operator that has:
 - 4.1.1.1. Plant personnel who are responsible for the Real-time control of a generator and receive Operating Instruction(s) from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.
- ~~5. **Effective Date:** See Implementation Plan for Project 2007-06-2.~~

B. Requirements and Measures

- R1.** Each Generator Operator shall provide training to personnel identified in Applicability section 4.1.1.1. on the operational functionality of Protection Systems and Remedial Action Schemes (RAS) that affect the output of the generating Facility(ies) it operates. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M1.** Each Generator Operator shall have available for inspection, evidence that the applicable personnel completed training. This evidence may be documents such as training records showing successful completion of training that includes training materials, the name of the person, and date of training.

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.

- The Generator Operator shall keep data or evidence of Requirement R1 for the current year and three previous 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: - one applicable personnel at a single Facility, or 5% or less of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: - two applicable personnel at a single Facility, or - more than 5% and less than or equal to 10% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: - three applicable personnel at a single Facility, or - more than 10% and less than or equal to 15% of the total applicable personnel of the Generator Operator.	The Generator Operator failed to provide training as described in Requirement R1 to the greater of: - five or more applicable personnel at a single Facility, or - more than 15% of the total applicable personnel of the Generator Operator. OR The Generator Operator failed to provide training as described in Requirement R1 to its applicable personnel.

D. Regional Variances

None.

E. Associated Documents

Project 2007-06.2 Implementation Plan¹

¹ http://www.nerc.com/pa/Stand/Project200706_2SystemProtectionCoordinationDL/Project_2007_06_2_Imp_Plan_Draft_1_2016_03_10_Clean.pdf

Version History

Version	Date	Action	Change Tracking
1	August 11, 2016	Adopted by the NERC Board of Trustees	New standard developed under Project 2007-06.2

Guidelines and Technical Basis

Requirement R1

The Generator Operator (GOP) monitors and controls its generating Facilities in Real-time to maintain reliability. To accomplish this, applicable plant personnel responsible for Real-time control of a generating Facility must be trained on how the operational functionality of Protection Systems and Remedial Action Schemes (RAS) are applied and the affects they may have on a generating Facility. Although, training does not have to be Facility-specific, the standard applies to plant operating personnel associated with the specific Facility to which they have Real-time control. This does not include plant personnel not responsible for Real-time control (e.g., fuel or coal handlers, electricians, machinists, or maintenance staff).

A periodicity for training is not specified in Requirement R1 because the GOP must ensure its plant personnel who have Real-time control of a generator are trained. The Generator Operator must also ensure it provides applicable training that results from changes to the operational functionality of the Protection Systems and Remedial Action Schemes that affect the output of the generation Facility(ies).

The phrase “operational functionality” focuses the training on how Protection Systems operate and prevent possible damage to Elements. It also addresses how RAS detects pre-determined BES conditions and automatically takes corrective actions.

Considerations for operational functionality may include, but are not limited to the following:

- Purpose of protective relays and RAS
- Zones of protection
- Protection communication systems (e.g., line current differential, direct transfer trip, etc.)
- Voltage and current inputs
- Station dc supply associated with protective functions
- Resulting actions – tripping/closing of breakers; tripping of a generator step-up (GSU) transformer; or generator ramping/tripping control functions

Requirement R1 focuses on the operational functionality of Protection Systems and Remedial Action Schemes specific to the generating plant and not the Bulk Electric System.

This requirement focuses on those systems that are related to the electrical output of the generator. Protective systems which trip breakers serving station auxiliary loads (e.g., such as pumps, fans, or fuel handling equipment) are not included in the scope of this training. Furthermore, protection of secondary unit substation (SUS) or low voltage switchgear transformers and relays protecting other downstream plant electrical distribution system components are not in the scope of this training, even if a trip of these devices might eventually result in a trip of the generating unit.

Rationale

Rationale for Requirement R1: Protection Systems and Remedial Action Schemes (RAS) are an integral part of reliable Bulk Electric System (BES) operation. This requirement addresses the reliability objective of ensuring that Generator Operator (GOP) plant operating personnel understand the operational functionality of Protection Systems and RAS and their effects on generating Facilities.

A. Introduction

1. **Title:** Generator Relay Loadability
2. **Number:** PRC-025-2
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Generator Owner that applies load-responsive protective relays¹ at the terminals of the Elements listed in 4.2, Facilities.
 - 4.1.2. Transmission Owner that applies load-responsive protective relays¹ at the terminals of the Elements listed in 4.2, Facilities.
 - 4.1.3. Distribution Provider that applies load-responsive protective relays¹ at the terminals of the Elements listed in 4.2, Facilities.
 - 4.2. **Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:
 - 4.2.1. Generating unit(s).
 - 4.2.2. Generator step-up (i.e., GSU) transformer(s).
 - 4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.²
 - 4.2.4. 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, except that Elements may also supply generating plant loads.
 - 4.2.5. Elements utilized in the aggregation of dispersed power producing resources.
5. ~~Effective Date: See Implementation Plan~~

¹ Relays include low voltage protection devices that have adjustable settings.

² These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.³

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

- R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
- M1.** For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

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

³ [Interim Report](http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf): Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>).

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:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with <i>PRC-025-2 – Attachment 1: Relay Settings</i> , on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, “Considerations for Power Plant and Transmission System Protection Coordination,” technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition.” (Date of Publication: March 2016)

IEEE C37.102-2006, “IEEE Guide for AC Generator Protection.” (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04
2	February 8, 2018	Adopted by NERC Board of Trustees	Revision

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective 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).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.⁴
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

⁴ IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

PRC-025-2 – Generator Relay Loadability

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, 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). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting. The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria	
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

⁵ Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output – 100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria	
Relays installed on generator-side ⁶ of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
	The same application continues on the next page with a different relay type				

⁶ If the relay is installed on the high-side of the GSU transformer, use Option 14.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria	
Relays installed on generator-side ⁷ of the Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
	8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation		
The same application continues on the next page with a different relay type					

⁷ If the relay is installed on the high-side of the GSU transformer use, Option 15.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on generator-side ⁸ of the Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

⁸ If the relay is installed on the high-side of the GSU transformer use, Option 16.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system ⁹	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51) ¹⁰	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system ¹¹	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

⁹ If the relay is installed on the high-side of the GSU transformer, use Option 17.

¹⁰ If the relay is installed on the high-side of the GSU transformer, use Option 18.

¹¹ If the relay is installed on the high-side of the GSU transformer, use Option 19.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer, ¹² including relays installed on the remote end of line, for 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 (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
		The same application continues on the next page with a different relay type		

¹² If the relay is installed on the generator-side of the GSU transformer, use Option 7.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on the high-side of the GSU transformer, ¹³ including relays installed at the remote end of the line, for 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 (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

¹³ If the relay is installed on the generator-side of the GSU transformer, use Option 8.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on the high-side of the GSU transformer, ¹⁴ including relays installed at the remote end of the line, for 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 (except that Elements may also supply generating plant load.) –connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

¹⁴ If the relay is installed on the generator-side of the GSU transformer, use Option 9.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on the high-side of the GSU transformer, ¹⁵ including relays installed on the remote end of line, for 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 (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

¹⁵ If the relay is installed on the generator-side of the GSU transformer, use Option 10.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on the high-side of the GSU transformer, ¹⁶ including, relays installed on the remote end of the line, for 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 (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

¹⁶ If the relay is installed on the generator-side of the GSU transformer, use Option 11.

PRC-025-2 – Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Setting Criteria
Relays installed on the high-side of the GSU transformer, ¹⁷ including relays installed on the remote end of the line, for 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 (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

¹⁷ If the relay is installed on the generator-side of the GSU transformer, use Option 12.

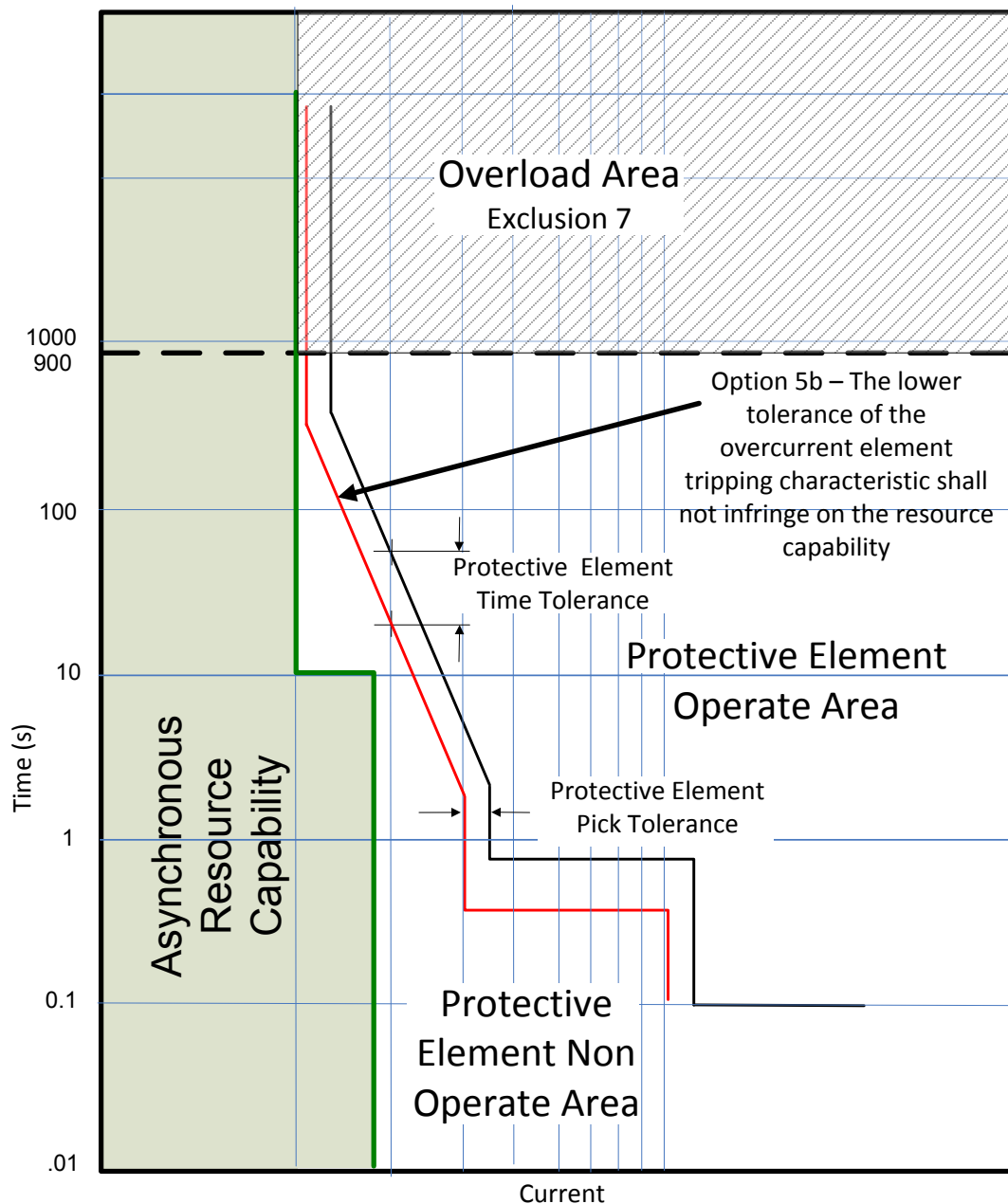


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "[Considerations for Power Plant and Transmission System Protection Coordination](http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf)," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.¹⁸

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is 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 this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

¹⁸ <http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf>.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria (“Table 1”) in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner’s interconnection facility (in some cases labeled a “transmission Facility” or “generator leads”) consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term “generator interconnection Facility” consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as “Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant” to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for 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. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since 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 are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

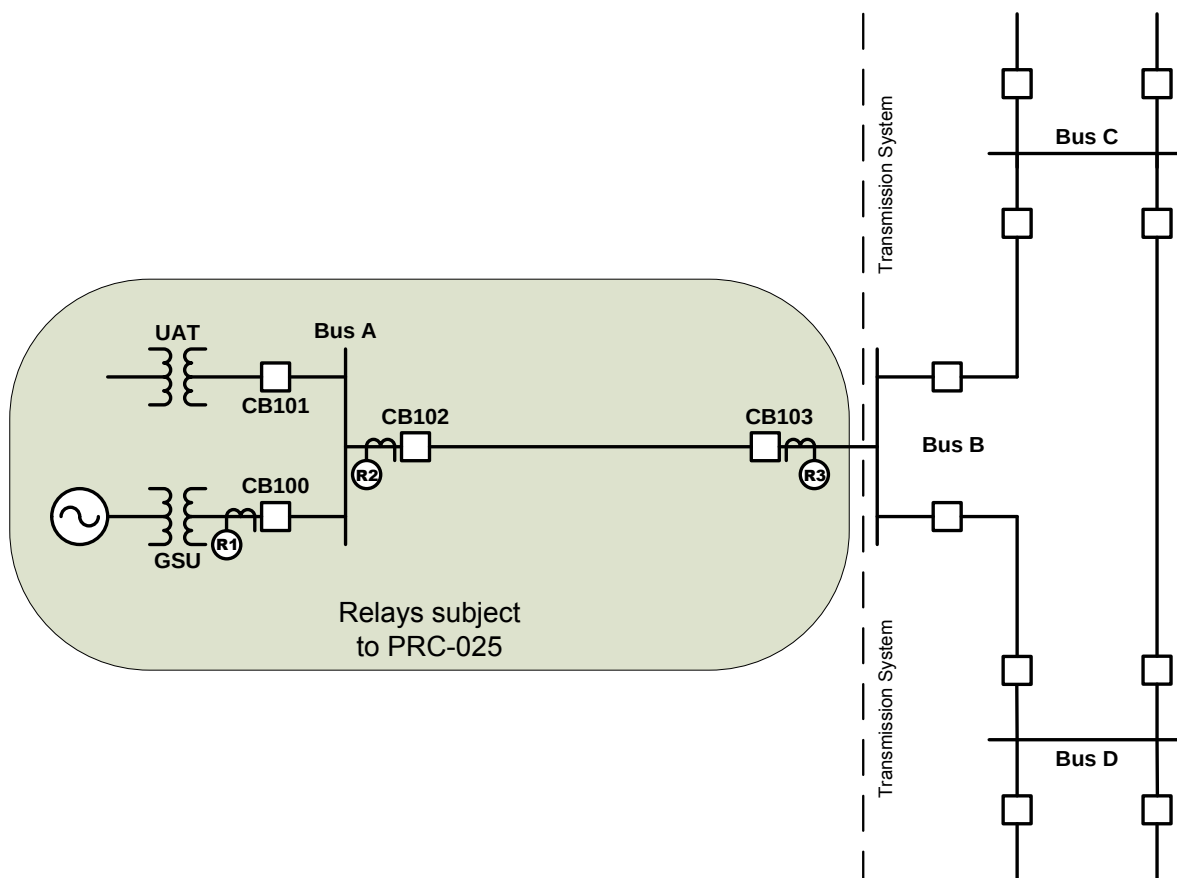


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for 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

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differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since 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 are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

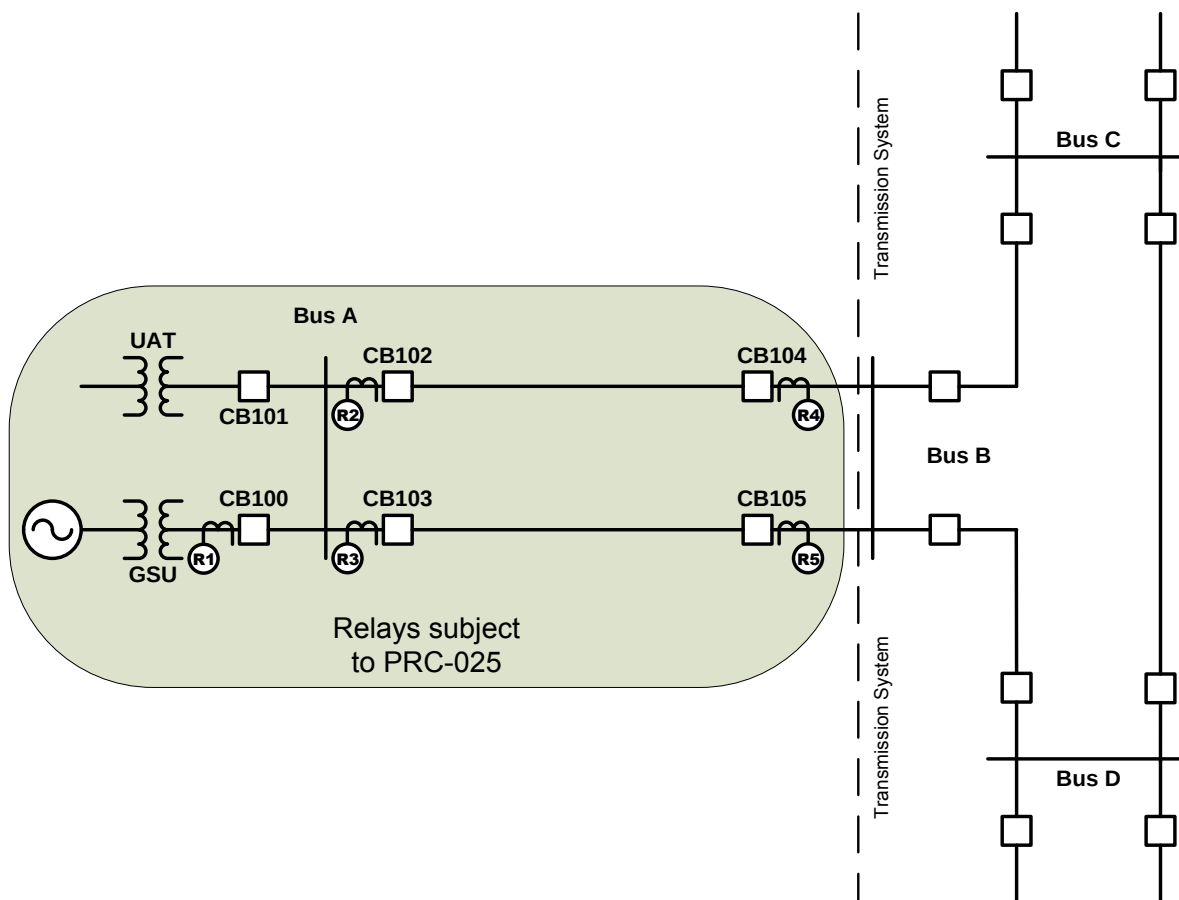


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

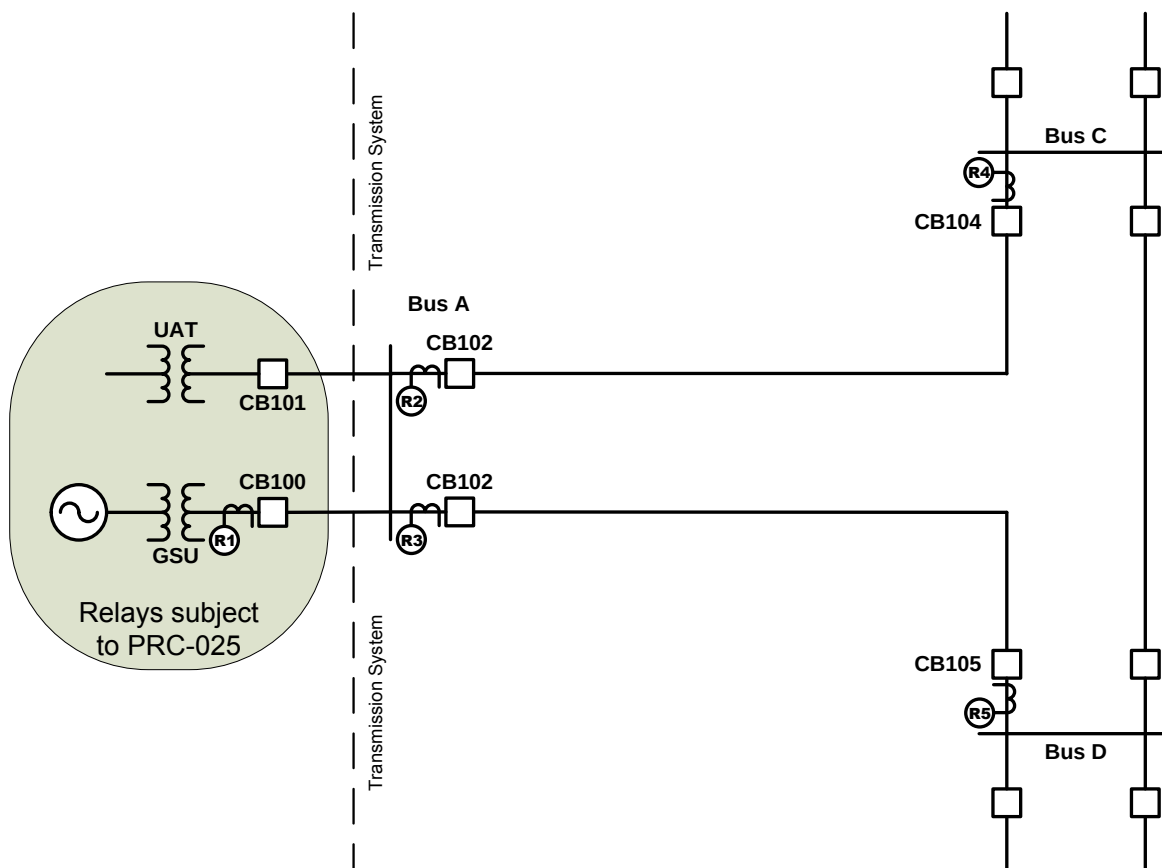


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called [Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition](#),¹⁹ March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system” or “feeders”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

¹⁹ http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

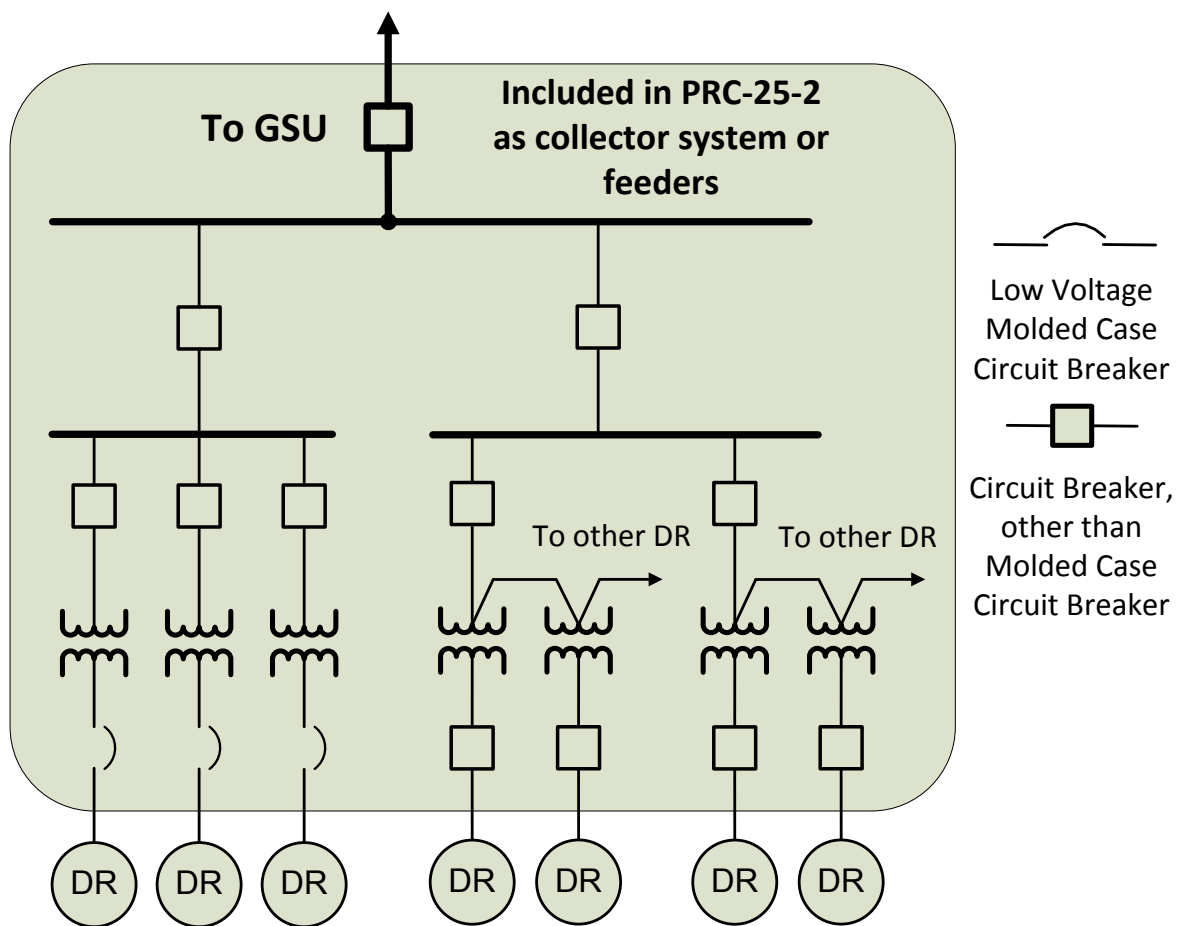


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column “Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

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 are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, “Guide for AC Generator Protection,” describes the purpose of this protection as follows (emphasis added):

*“The distance relay applied for this function is intended to isolate the generator from the power system for a fault **that is not cleared by the transmission line breakers**. In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and **normal loading conditions**. However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers **to optimize coordination while still protecting the turbine generator**. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

*regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions. **Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.** With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting.”*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

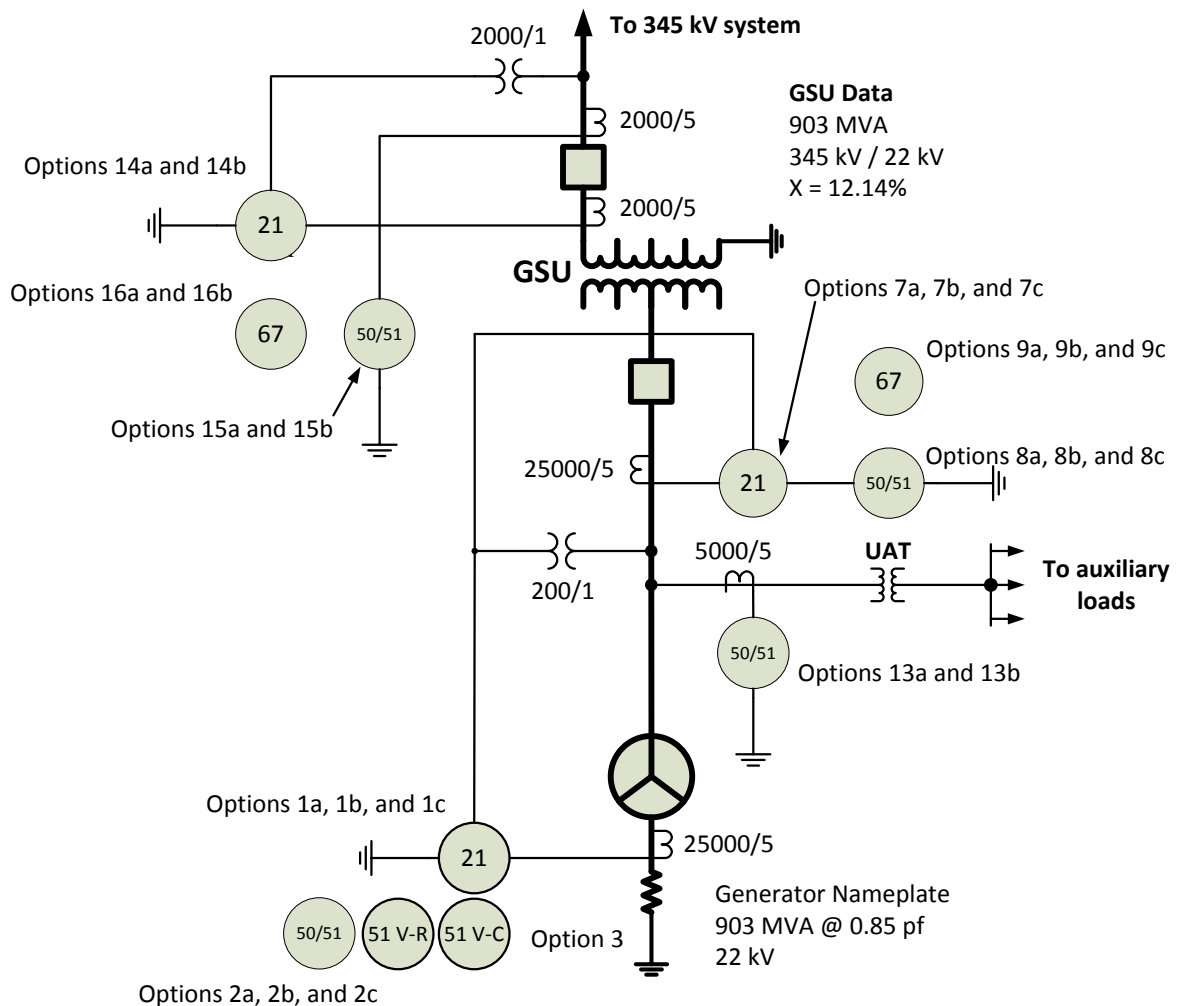


Figure 5: Relay Connection for corresponding synchronous options

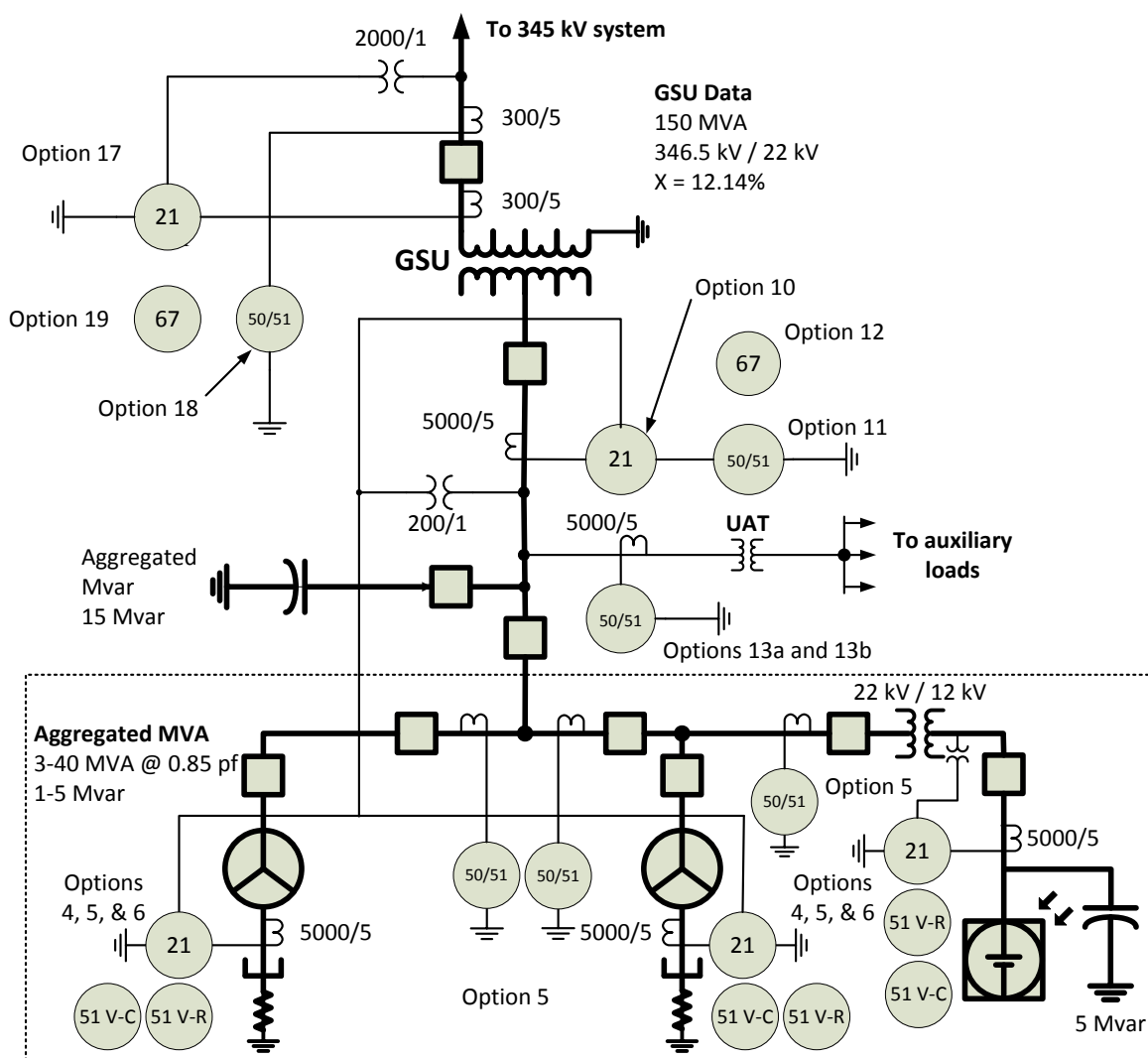


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and

any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator.

For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection

Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12) The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor,

including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016.” These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

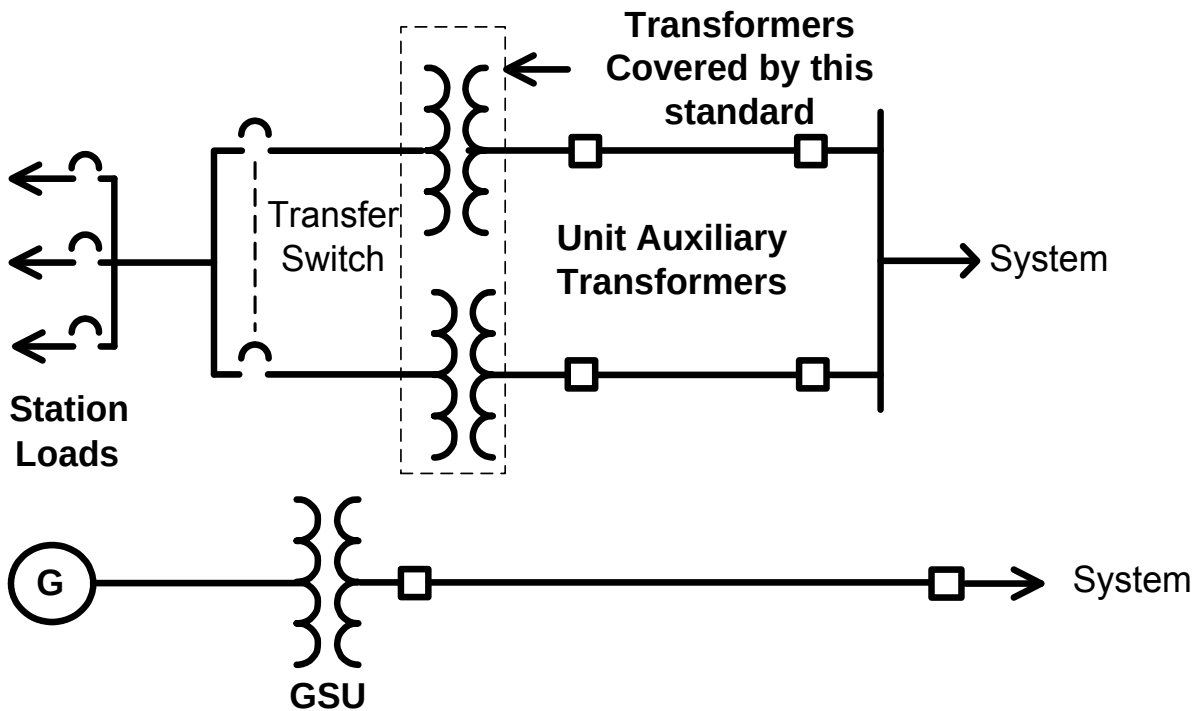
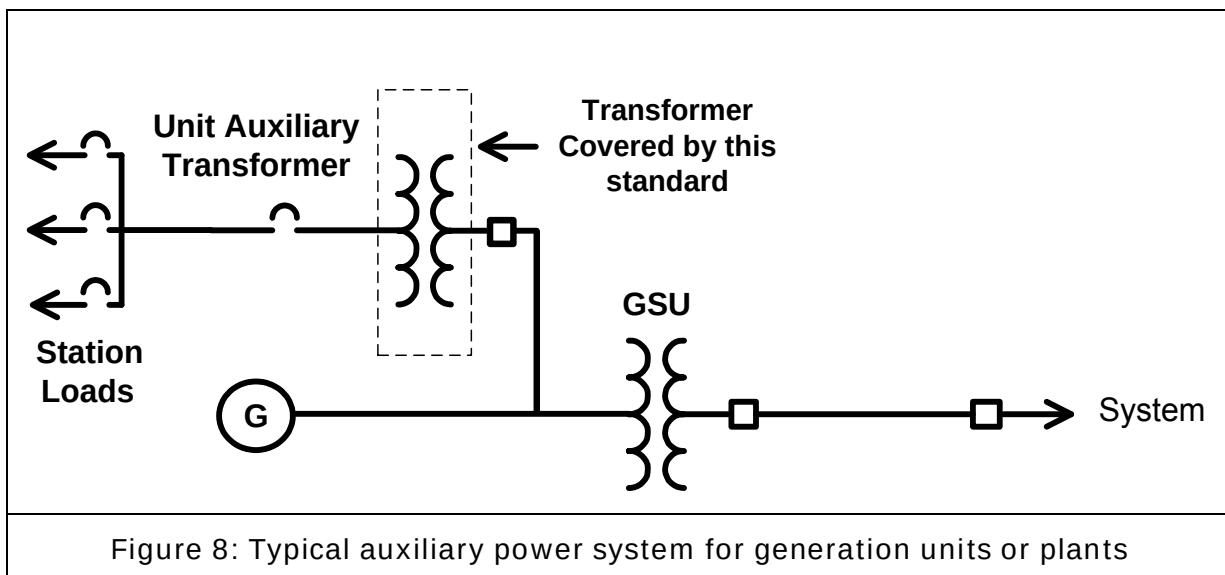


Figure 7: Auxiliary Power System (independent from generator)



The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at

the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18) Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	Input Values
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903 \text{ MVA}$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22 \text{ kV}$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0 \text{ MW}$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903 \text{ MVA}$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6 \text{ MVA}$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22 \text{ kV}}{346.5 \text{ kV}}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345 \text{ kV}$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60 \text{ MVA}$
UAT high-side voltage:	$V_{UAT} = 13.8 \text{ kV}$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15 \text{ Mvar}$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5 \text{ Mvar}$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40 \text{ MVA}$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (1)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (2)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (3)} \quad V_{\text{gen}} = 0.95 \text{ p.u.} \times V_{\text{nom}} \times GSU_{\text{ratio}}$$

$$V_{\text{gen}} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{\text{gen}} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (4)} \quad S = P_{\text{Synch\_reported}} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (5)} \quad Z_{\text{pri}} = \frac{V_{\text{gen}}^2}{S^*}$$

$$Z_{\text{pri}} = \frac{(20.81 \text{ kV})^2}{1347.4 \angle -58.7^\circ \text{ MVA}}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321 \angle 58.7^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (6)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321 \angle 58.7^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321 \angle 58.7^\circ \Omega \times 25$$

$$Z_{sec} = 8.035 \angle 58.7^\circ \Omega$$

To satisfy the 115% margin in Option 1a:

$$\text{Eq. (7)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \text{ limit}} = \frac{8.035 \angle 58.7^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 6.9873 \angle 58.7^\circ \Omega$$

$$\theta_{transient \text{ load angle}} = 58.7^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. (8)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{6.9873 \Omega}{\cos(85.0^\circ - 58.7^\circ)}$$

$$Z_{max} < \frac{6.9873 \Omega}{0.896}$$

$$Z_{max} < 7.793 \angle 85.0^\circ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (9)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (10)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

$$\text{Eq. (11)} \quad P_{pu} = \frac{P_{\text{Synch\_reported}}}{MVA_{\text{base}}}$$

$$P_{pu} = \frac{700.0 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 0.91 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (12)} \quad Q_{pu} = \frac{Q}{MVA_{\text{base}}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

$$\text{Eq. (13)} \quad X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}} \right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right)$$

$$X_{pu} = 0.1032 \text{ p.u.}$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\text{Eq. (14)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.7^\circ$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7^\circ) \pm \sqrt{|0.85|^2 \times \cos^2(6.7^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991 \text{ p.u.}$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

$$\text{Eq. (16)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.3^\circ$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3^\circ) \pm \sqrt{|0.85|^2 \times \cos^2(6.3^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998 \text{ p.u.}$$

To account for system high-side nominal voltage and the transformer tap ratio:

$$\text{Eq. (18)} \quad V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.90 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (19)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

$$\text{Eq. (20)} \quad Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90 \text{ kV})^2}{1347.4 \angle -58.7^\circ \text{ MVA}}$$

$$Z_{pri} = 0.356 \angle 58.7^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (21)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356 \angle 58.7^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356 \angle 58.7^\circ \Omega \times 25$$

$$Z_{sec} = 8.900 \angle 58.7^\circ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

$$\text{Eq. (22)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \text{ limit}} = \frac{8.900 \angle 58.7^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 7.74 \angle 58.7^\circ \Omega$$

$$\theta_{transient \text{ load angle}} = 58.7^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. (23)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{7.74 \Omega}{\cos(85.0^\circ - 58.7^\circ)}$$

Example Calculations: Options 1b and 7b

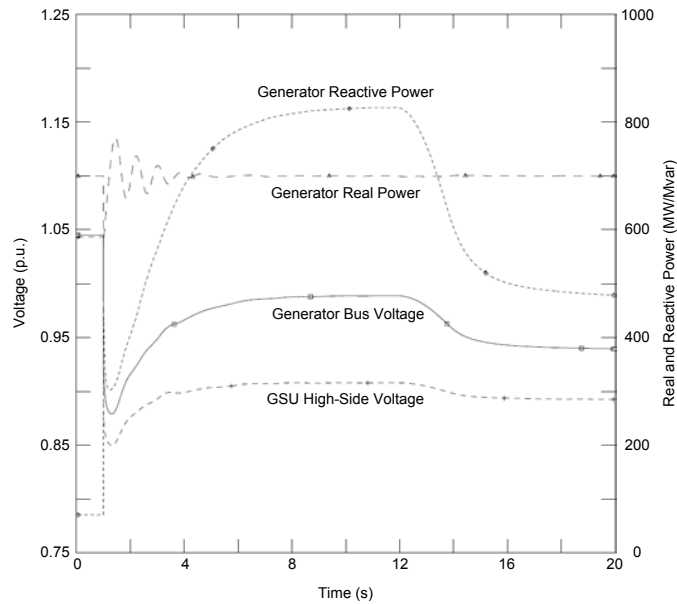
$$Z_{max} < \frac{7.74 \, \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0^\circ \, \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4 \, \text{Mvar}$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76 \, \text{kV}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0 \text{ MW}$$

Apparent power (S):

$$\text{Eq. (24)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j827.4 \text{ Mvar}$$

$$S = 1083.8 \angle 49.8^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (25)} \quad Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76 \text{ kV})^2}{1083.8 \angle -49.8^\circ \text{ MVA}}$$

$$Z_{pri} = 0.437 \angle 49.8^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (26)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437 \angle 49.8^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437 \angle 49.8^\circ \Omega \times 25$$

$$Z_{sec} = 10.92 \angle 49.8^\circ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

$$\text{Eq. (27)} \quad Z_{sec\ limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\ limit} = \frac{10.92 \angle 49.8^\circ \Omega}{1.15}$$

$$Z_{sec\ limit} = 9.50 \angle 49.8^\circ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. (28)} \quad Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0^\circ - 49.8^\circ)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63 \angle 85.0^\circ\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

$$\text{Eq. (29)} \quad P = GEN_{synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

$$\text{Eq. (30)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (31)} \quad V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (32)} \quad S = P_{\text{Synch\_reported}} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (33)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri} = 37383 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (34)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.477 \text{ A}$$

To satisfy the 115% margin in Option 2a:

$$\text{Eq. (35)} \quad I_{sec \text{ limit}} > I_{sec} \times 115\%$$

$$I_{sec \text{ limit}} > 7.477 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 8.598 \text{ A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

$$\text{Eq. (36)} \quad P = GEN_{\text{synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (37)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

$$\text{Eq. (38)} \quad P_{pu} = \frac{P_{\text{synch\_reported}}}{MVA_{\text{base}}}$$

$$P_{pu} = \frac{700.0 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 0.91 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (39)} \quad Q_{pu} = \frac{Q}{MVA_{\text{base}}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Example Calculations: Option 2b

Transformer impedance:

$$\begin{aligned} \text{Eq. (40)} \quad X_{pu} &= X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}} \\ X_{pu} &= 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right) \\ X_{pu} &= 0.1032 \text{ p.u.} \end{aligned}$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\text{Eq. (41)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.7^\circ$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7^\circ) \pm \sqrt{|0.85|^2 \times \cos^2(6.7^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991 \text{ p.u.}$$

Example Calculations: Option 2b

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

$$\text{Eq. (43)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.3^\circ$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3^\circ) \pm \sqrt{|0.85|^2 \times \cos^2(6.3^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998 \text{ p.u.}$$

To account for system high-side nominal voltage and the transformer tap ratio:

$$\text{Eq. (45)} \quad V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.90 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (46)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Example Calculations: Option 2b

Primary current (I_{pri}):

$$\text{Eq. (47)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 21.90 \text{ kV}}$$

$$I_{pri} = 35553 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (48)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.111 \text{ A}$$

To satisfy the 115% margin in Option 2b:

$$\text{Eq. (49)} \quad I_{seclimit} > I_{sec} \times 115\%$$

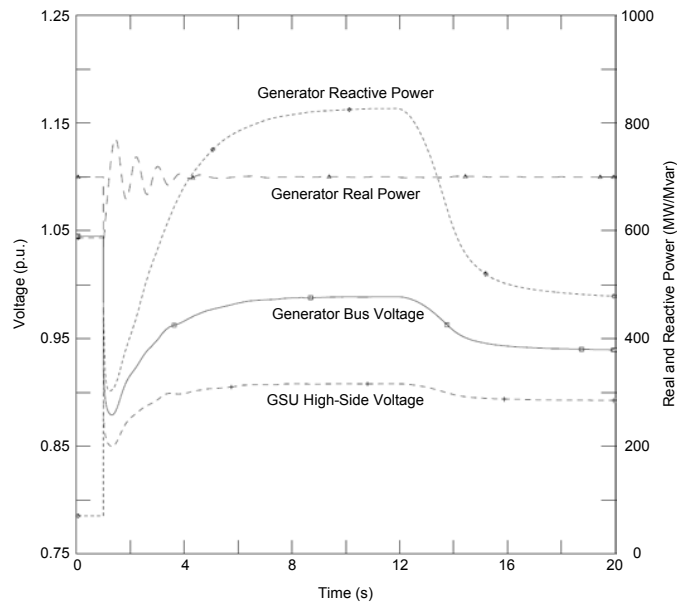
$$I_{seclimit} > 7.111 \text{ A} \times 1.15$$

$$I_{seclimit} > 8.178 \text{ A}$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4 \text{ Mvar}$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76 \text{ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0 \text{ MW}$$

Example Calculations: Option 2c

Apparent power (S):

$$\begin{aligned}\text{Eq. (50)} \quad S &= P_{\text{Synch\_reported}} + jQ \\ S &= 700.0 \text{ MW} + j827.4 \text{ Mvar} \\ S &= 1083.8 \angle 49.8^\circ \text{ MVA}\end{aligned}$$

Primary current (I_{pri}):

$$\begin{aligned}\text{Eq. (51)} \quad I_{\text{pri}} &= \frac{S}{\sqrt{3} \times V_{\text{bus\_simulated}}} \\ I_{\text{pri}} &= \frac{1083.8 \text{ MVA}}{1.73 \times 21.76 \text{ kV}} \\ I_{\text{pri}} &= 28790 \text{ A}\end{aligned}$$

Secondary current (I_{sec}):

$$\begin{aligned}\text{Eq. (52)} \quad I_{\text{sec}} &= \frac{I_{\text{pri}}}{CT_{\text{ratio}}} \\ I_{\text{sec}} &= \frac{28790 \text{ A}}{\frac{25000}{5}} \\ I_{\text{sec}} &= 5.758 \text{ A}\end{aligned}$$

To satisfy the 115% margin in Option 2c:

$$\begin{aligned}\text{Eq. (53)} \quad I_{\text{sec limit}} &> I_{\text{sec}} \times 115\% \\ I_{\text{sec limit}} &> 5.758 \text{ A} \times 1.15 \\ I_{\text{sec limit}} &> 6.622 \text{ A}\end{aligned}$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (54)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

The voltage setting shall be set less than 75% of the generator bus voltage:

$$\text{Eq. (55)} \quad V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9 \text{ kV} \times 0.75$$

$$V_{setting} < 16.429 \text{ kV}$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (56)} \quad P = GEN_{Asynch\_nameplate} \times pf$$

$$P = 40 \text{ MVA} \times 0.85$$

$$P = 34.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (57)} \quad Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40 \text{ MVA} \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1 \text{ Mvar}$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (58)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (59)} \quad S = P + jQ$$

$$S = 34.0 \text{ MW} + j21.1 \text{ Mvar}$$

$$S = 40.0 \angle 31.8^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (60)} \quad Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9 \text{ kV})^2}{40.0 \angle -31.8^\circ \text{ MVA}}$$

$$Z_{pri} = 11.99 \angle 31.8^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (61)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99 \angle 31.8^\circ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99 \angle 31.8^\circ \Omega \times 5$$

$$Z_{sec} = 59.95 \angle 31.8^\circ \Omega$$

To satisfy the 130% margin in Option 4:

$$\text{Eq. (62)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{sec\ limit} = \frac{59.95 \angle 31.8^\circ \Omega}{1.30}$$

$$Z_{sec\ limit} = 46.12 \angle 31.8^\circ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

$$\text{Eq. (63)} \quad Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12 \Omega}{\cos(85.0^\circ - 31.8^\circ)}$$

$$Z_{max} < \frac{46.12 \Omega}{0.599}$$

$$Z_{max} < 77.0 \angle 85.0^\circ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. (64)} \quad P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

$$\text{Eq. (65)} \quad Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (66)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (67)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (68)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 3473 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (69)} \quad I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2^\circ \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2^\circ \text{ A}$$

To satisfy the 130% margin in Option 5a:

$$\text{Eq. (70)} \quad I_{sec\ limit} > I_{sec} \times 130\%$$

$$I_{sec\ limit} > 3.473 \angle -39.2^\circ \text{ A} \times 1.30$$

Example Calculations: Option 5a

$$I_{sec\ limit} > 4.52 \angle -39.2^\circ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. (71)} \quad P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \text{ MVA} \times 0.85$$

$$P = 102.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (72)} \quad Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \text{ Mvar}$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (73)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (74)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Example Calculations: Option 5b

Primary current (I_{pri}):

$$\text{Eq. (75)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 3473 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (76)} \quad I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2^\circ \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2^\circ \text{ A}$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{synch}):

$$\text{Eq. (77)} \quad P_{synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{synch} = 903 \text{ MVA} \times 0.85$$

$$P_{synch} = 767.6 \text{ MW}$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

$$\text{Eq. (78)} \quad Q_{synch} = 150\% \times P_{synch}$$

$$Q_{synch} = 1.50 \times 767.6 \text{ MW}$$

$$Q_{synch} = 1151.3 \text{ MW}$$

Apparent power (S_{synch}):

$$\text{Eq. (79)} \quad S_{synch} = P_{synch\_reported} + jQ_{synch}$$

$$S_{synch} = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

$$\text{Eq. (80)} \quad P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \text{ MVA} \times 0.85$$

$$P_{Asynch} = 102.0 \text{ MW}$$

Reactive Power output (Q_{Asynch}):

$$\text{Eq. (81)} \quad Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q_{Asynch} = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \text{ Mvar}$$

Apparent power (S_{Asynch}):

$$\text{Eq. (82)} \quad S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

$$\text{Eq. (83)} \quad V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

$$\text{Eq. (84)} \quad S = 115\% \times (P_{Synch\_reported} + jQ_{Synch}) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0 \text{ MW} + j1151.3 \text{ Mvar}) + 1.30 \times (102.0 \text{ MW} + j83.2 \text{ Mvar})$$

$$S = 1711.8 \angle 56.8^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (85)} \quad Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81 \text{ kV})^2}{1711.8 \angle -56.8^\circ \text{ MVA}}$$

$$Z_{pri} = 0.2527 \angle 56.8^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (86)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527 \angle 56.8^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527 \angle 56.8^\circ \Omega \times 25$$

$$Z_{sec} = 6.32 \angle 56.8^\circ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

$$\begin{aligned}\text{Eq. (87)} \quad Z_{\text{sec limit}} &= \frac{Z_{\text{sec}}}{100\%} \\ Z_{\text{sec limit}} &= \frac{6.32 \angle 56.8^\circ \Omega}{1.00} \\ Z_{\text{sec limit}} &= 6.32 \angle 56.8^\circ \Omega \\ \theta_{\text{transient load angle}} &= 56.8^\circ\end{aligned}$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

$$\begin{aligned}\text{Eq. (88)} \quad Z_{\text{max}} &< \frac{|Z_{\text{sec limit}}|}{\cos(\theta_{\text{MTA}} - \theta_{\text{transient load angle}})} \\ Z_{\text{max}} &< \frac{6.32 \Omega}{\cos(85.0^\circ - 56.8^\circ)} \\ Z_{\text{max}} &< \frac{6.32 \Omega}{0.881} \\ Z_{\text{max}} &< 7.17 \angle 85.0^\circ \Omega\end{aligned}$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{\text{Synch\_nameplate}}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

$$\begin{aligned}\text{Eq. (89)} \quad P &= GEN_{\text{Synch\_nameplate}} \times pf \\ P &= 903 \text{ MVA} \times 0.85 \\ P &= 767.6 \text{ MW}\end{aligned}$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

$$\text{Eq. (90)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

$$\text{Eq. (91)} \quad V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (92)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (93)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri} = 37383 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (94)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383 \text{ A}}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477 \text{ A}$$

To satisfy the 115% margin in Options 8a and 9a:

$$\text{Eq. (95)} \quad I_{sec\ limit} > I_{sec} \times 115\%$$

$$I_{sec\ limit} > 7.477 \text{ A} \times 1.15$$

$$I_{sec\ limit} > 8.598 \text{ A}$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

$$\text{Eq. (96)} \quad P = GEN_{synch\_nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (97)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

$$\text{Eq. (98)} \quad P_{pu} = \frac{P_{synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0 \text{ MW}}{767.6 \text{ MVA}}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (99)} \quad Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Transformer impedance:

$$\text{Eq. (100)} \quad X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right)$$

$$X_{pu} = 0.1032 \text{ p.u.}$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\text{Eq. (101)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)} \right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7^\circ) \pm \sqrt{|0.85|^2 \times \cos^2(6.7^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991 \text{ p.u.}$$

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

$$\text{Eq. (103)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.3^\circ$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3^\circ) \pm \sqrt{|0.85|^2 \times \cos^2(6.3^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998 \text{ p.u.}$$

To account for system high-side nominal voltage and the transformer tap ratio:

$$\text{Eq. (105)} \quad V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.90 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (106)} \quad S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (107)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 21.90 \text{ kV}}$$

$$I_{pri} = 35553 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (108)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.111 \text{ A}$$

To satisfy the 115% margin in Options 8b and 9b:

$$\text{Eq. (109)} \quad I_{sec \text{ limit}} > I_{sec} \times 115\%$$

$$I_{sec \text{ limit}} > 7.111 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 8.178 \text{ A}$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

$$\text{Eq. (110)} \quad P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903 \text{ MVA} \times .85$$

$$P_{Synch} = 767.6 \text{ MW}$$

Reactive Power output (Q_{Synch}):

$$\text{Eq. (111)} \quad Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6 \text{ MW}$$

$$Q_{Synch} = 1151.3 \text{ Mvar}$$

Apparent power (S_{Synch}):

$$\text{Eq. (112)} \quad S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S_{Synch} = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

$$\text{Eq. (113)} \quad V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Primary current ($I_{pri-sync}$):

$$\text{Eq. (114)} \quad I_{pri-sync} = \frac{115\% \times S_{Synch}^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7^\circ \text{ MVA})}{1.73 \times 20.81 \text{ kV}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7^\circ A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

$$\text{Eq. (115)} \quad P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \text{ MVA} \times 0.85$$

$$P_{Asynch} = 102.0 \text{ MW}$$

Reactive Power output (Q_{Asynch}):

$$\text{Eq. (116)} \quad Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \text{ Mvar}$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

$$\text{Eq. (117)} \quad V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S_{Asynch}):

$$\text{Eq. (118)} \quad S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \text{ MW} + j83.2 \text{ Mvar})$$

$$S_{Asynch} = 171.1 \angle 39.2^\circ \text{ MVA}$$

Primary current ($I_{pri-async}$):

$$\text{Eq. (119)} \quad I_{pri-async} = \frac{S_{Asynch}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2^\circ \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri-async} = 4755 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (120)} \quad I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7^\circ \text{ A}}{\frac{25000}{5}} + \frac{4755 \angle -39.2^\circ \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8^\circ \text{ A}$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

$$\text{Eq. (121)} \quad I_{sec \text{ limit}} > I_{sec} \times 100\%$$

$$I_{sec \text{ limit}} > 9.514 \angle -56.8^\circ \text{ A} \times 1.00$$

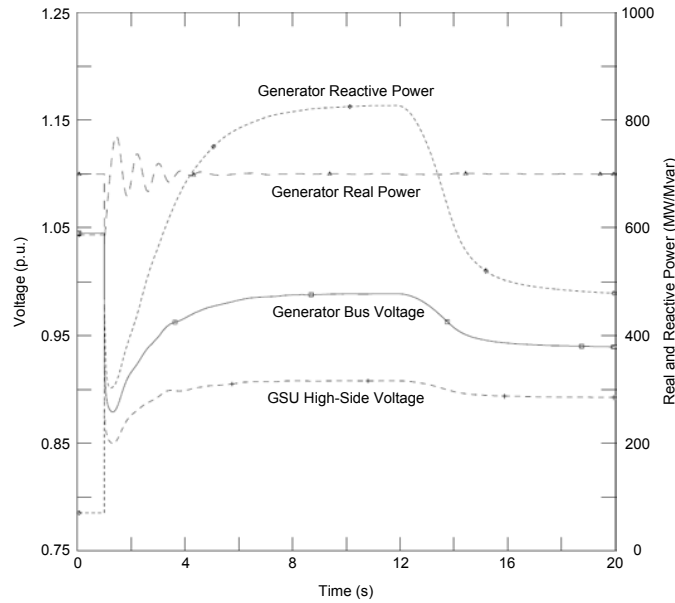
$$I_{sec \text{ limit}} > 9.514 \angle -56.8^\circ \text{ A}$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4 \text{ Mvar}$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76 \text{ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \text{ MW}$$

Apparent power (S):

$$\text{Eq. (122)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j827.4 \text{ Mvar}$$

$$S = 1083.8 \angle 49.8^\circ$$

Primary current (I_{pri}):

$$\text{Eq. (123)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8 \text{ MVA}}{1.73 \times 21.76 \text{ kV}}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790 \text{ A}$$

Secondary current (I_{sec}):

$$\begin{aligned} \text{Eq. (124)} \quad I_{sec} &= \frac{I_{pri}}{CT_{ratio}} \\ I_{sec} &= \frac{28790 \text{ A}}{\frac{25000}{5}} \\ I_{sec} &= 5.758 \text{ A} \end{aligned}$$

To satisfy the 115% margin in Options 8c and 9c:

$$\begin{aligned} \text{Eq. (125)} \quad I_{sec \text{ limit}} &> I_{sec} \times 115\% \\ I_{sec \text{ limit}} &> 5.758 \text{ A} \times 1.15 \\ I_{sec \text{ limit}} &> 6.622 \text{ A} \end{aligned}$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\begin{aligned} \text{Eq. (126)} \quad P &= 3 \times GEN_{Asynch\_nameplate} \times pf \\ P &= 3 \times 40 \text{ MVA} \times 0.85 \\ P &= 102.0 \text{ MW} \end{aligned}$$

Reactive Power output (Q):

$$\begin{aligned} \text{Eq. (127)} \quad Q &= MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))) \\ Q &= 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85))) \\ Q &= 83.2 \text{ Mvar} \end{aligned}$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (128)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (129)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (130)} \quad Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9 \text{ kV})^2}{131.6 \angle -39.2^\circ \text{ MVA}}$$

$$Z_{pri} = 3.644 \angle 39.2^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (131)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644 \angle 39.2^\circ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644 \angle 39.2^\circ \Omega \times 5$$

$$Z_{sec} = 18.22 \angle 39.2^\circ \Omega$$

To satisfy the 130% margin in Option 10:

$$\text{Eq. (132)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 10

$$Z_{sec\ limit} = \frac{18.22 \angle 39.2^\circ \Omega}{1.30}$$

$$Z_{sec\ limit} = 14.02 \angle 39.2^\circ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

$$\text{Eq. (133)} \quad Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02 \Omega}{\cos(85.0^\circ - 39.2^\circ)}$$

$$Z_{max} < \frac{14.02 \Omega}{0.6972}$$

$$Z_{max} < 20.11 \angle 85.0^\circ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. (134)} \quad P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

$$\text{Eq. (135)} \quad Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2 \text{ Mvar}$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (136)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (137)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (138)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 3473 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (139)} \quad I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2^\circ \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2^\circ \text{ A}$$

To satisfy the 130% margin in Options 11 and 12:

$$\text{Eq. (140)} \quad I_{sec \text{ limit}} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{sec\ limit} > 3.473 \angle -39.2^\circ A \times 1.30$$

$$I_{sec\ limit} > 4.515 \angle -39.2^\circ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

$$\text{Eq. (141)} \quad I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

$$\text{Eq. (142)} \quad I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ A$$

To satisfy the 150% margin in Options 13a:

$$\text{Eq. (143)} \quad I_{sec\ limit} > I_{sec} \times 150\%$$

$$I_{sec\ limit} > 2.51\ A \times 1.50$$

$$I_{sec\ limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

$$\text{Eq. (144)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (145)} \quad Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \text{ MW}$$

$$Q = 921.1 \text{ Mvar}$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

$$\text{Eq. (146)} \quad V_{\text{bus}} = 0.85 \text{ p.u.} \times V_{\text{nom}}$$

$$V_{\text{gen}} = 0.85 \times 345 \text{ kV}$$

$$V_{\text{gen}} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (147)} \quad S = P_{\text{Synch\_reported}} + jQ$$

$$S = 700.0 \text{ MW} + j921.1 \text{ Mvar}$$

$$S = 1157.0 \angle 52.77^\circ \text{ MVA}$$

$$\theta_{\text{transient load angle}} = 52.77^\circ$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

$$\text{Eq. (148)} \quad Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25 \text{ kV})^2}{1157.0 \angle -52.77^\circ \text{ MVA}}$$

$$Z_{pri} = 74.335 \angle 52.77^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (149)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio_{hv}}}{PT_{ratio_{hv}}}$$

$$Z_{sec} = 74.335 \angle 52.77^\circ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335 \angle 52.77^\circ \Omega \times 0.2$$

$$Z_{sec} = 14.867 \angle 52.77^\circ \Omega$$

To satisfy the 115% margin in Option 14a:

$$\text{Eq. (150)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \text{ limit}} = \frac{14.867 \angle 52.77^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 12.928 \angle 52.77^\circ \Omega$$

$$\theta_{transient \text{ load angle}} = 52.77^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. (151)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{12.928 \Omega}{\cos(85.0^\circ - 52.77^\circ)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928 \Omega}{0.846}$$

$$Z_{max} < 15.283 \angle 85.0^\circ \Omega$$

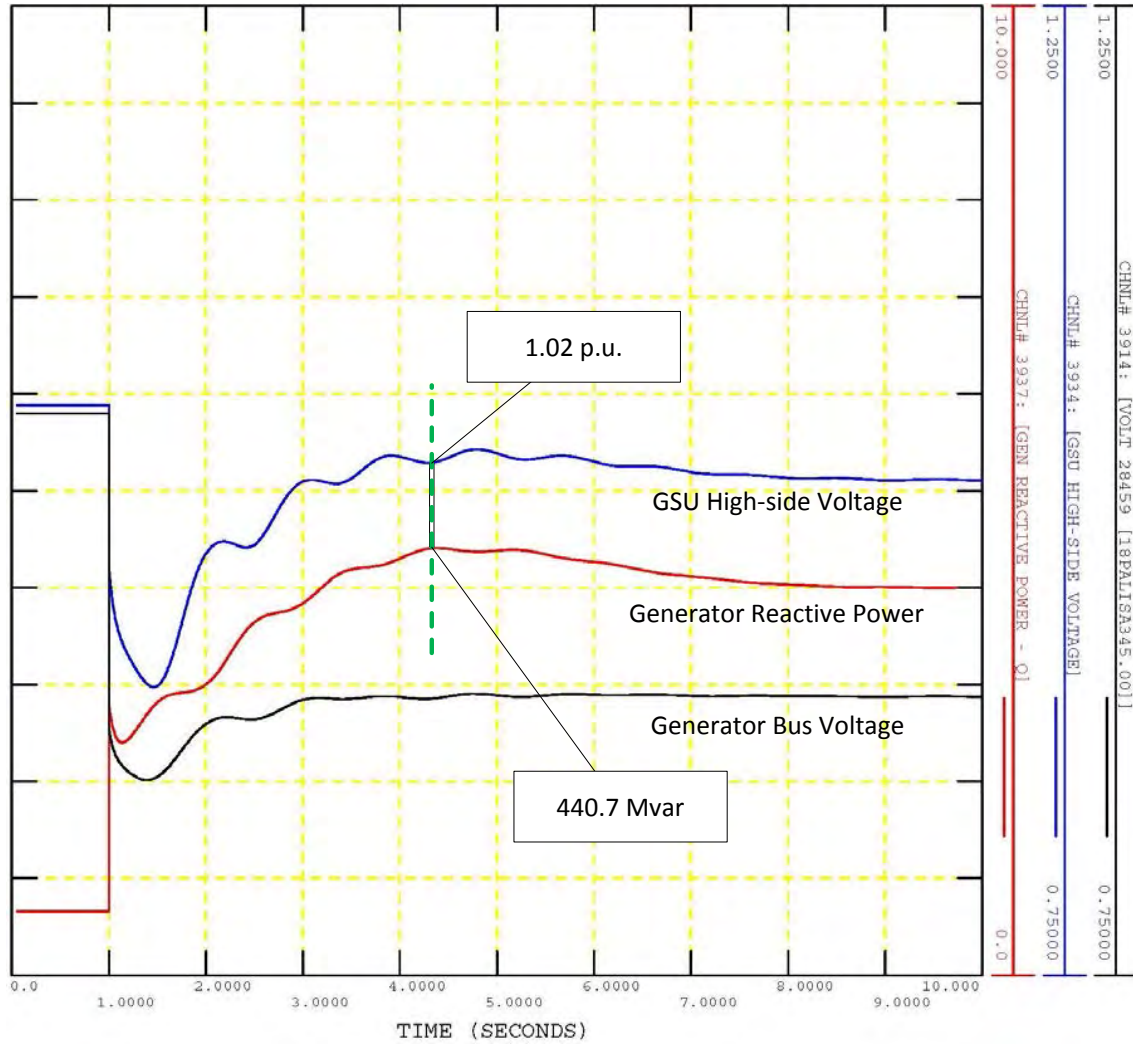
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7 \text{ Mvar}$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9 \text{ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \text{ MW}$$

Apparent power (S):

$$\text{Eq. (152)} \quad S = P_{Synch\_reported} + jQ$$

Example Calculations: Option 14b

$$S = 700.0 \text{ MW} + j440.7 \text{ Mvar}$$

$$S = 827.2 \angle 32.2^\circ \text{ MVA}$$

$$\theta_{\text{transient load angle}} = 32.2^\circ$$

Primary impedance (Z_{pri}):

$$\text{Eq. (153)} \quad Z_{\text{pri}} = \frac{V_{\text{bus\_simulated}}^2}{S^*}$$

$$Z_{\text{pri}} = \frac{(351.9 \text{ kV})^2}{827.2 \angle -32.2^\circ \text{ MVA}}$$

$$Z_{\text{pri}} = 149.7 \angle 32.2^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (154)} \quad Z_{\text{sec}} = Z_{\text{pri}} \times \frac{CT_{\text{ratio\_hv}}}{PT_{\text{ratio\_hv}}}$$

$$Z_{\text{sec}} = 149.7 \angle 32.2^\circ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{\text{sec}} = 149.7 \angle 32.2^\circ \Omega \times 0.2$$

$$Z_{\text{sec}} = 29.9 \angle 32.2^\circ \Omega$$

To satisfy the 115% margin in Option 14b:

$$\text{Eq. (155)} \quad Z_{\text{sec limit}} = \frac{Z_{\text{sec}}}{115\%}$$

$$Z_{\text{sec limit}} = \frac{29.9 \angle 32.2^\circ \Omega}{1.15}$$

$$Z_{\text{sec limit}} = 26.0 \angle 32.2^\circ \Omega$$

$$\theta_{\text{transient load angle}} = 32.2^\circ$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

$$\text{Eq. (156)} \quad Z_{max} < \frac{|Z_{sec limit}|}{\cos(\theta_{MTA} - \theta_{transient load angle})}$$

$$Z_{max} < \frac{26.0 \, \Omega}{\cos(85.0^\circ - 32.2^\circ)}$$

$$Z_{max} < \frac{26.0 \, \Omega}{0.61}$$

$$Z_{max} < 43.0 \angle 85.0^\circ \, \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

$$\text{Eq. (157)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (158)} \quad Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \text{ MW}$$

$$Q = 921.12 \text{ Mvar}$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

$$\text{Eq. (159)} \quad V_{bus} = 0.85 \text{ p.u.} \times V_{nom}$$

$$V_{bus} = 0.85 \times 345 \text{ kV}$$

$$V_{bus} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (160)} \quad S = P_{\text{Synch\_reported}} + jQ$$

$$S = 700.0 \text{ MW} + j921.12 \text{ Mvar}$$

$$S = 1157 \angle 52.8^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (161)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157 \angle -52.8^\circ \text{ MVA}}{1.73 \times 293.25 \text{ kV}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6 \angle -52.8^\circ A$$

Secondary current (I_{sec}):

$$\text{Eq. (162)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio_{hv}}}$$

$$I_{sec} = \frac{2280.6 \angle -52.8^\circ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8^\circ A$$

To satisfy the 115% margin in Options 15a and 16a:

$$\text{Eq. (163)} \quad I_{sec limit} > I_{sec} \times 115\%$$

$$I_{sec limit} > 5.701 \angle -52.8^\circ A \times 1.15$$

$$I_{sec limit} > 6.56 \angle -52.8^\circ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

$$\text{Eq. (164)} \quad P = GEN_{synch\_nameplate} \times pf$$

$$P = 903 MVA \times 0.85$$

$$P = 767.6 MW$$

Reactive Power output (Q):

$$\text{Eq. (165)} \quad Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 MW$$

$$Q = 921.12 Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

$$\text{Eq. (166)} \quad V_{bus\_remote\_substation} = 0.85 p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345 kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (167)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j921.12 \text{ Mvar}$$

$$S = 1157 \angle 52.8^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (168)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157 \angle -52.8^\circ \text{ MVA}}{1.73 \times 293.25 \text{ kV}}$$

$$I_{pri} = 2280.6 \angle -52.8^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (169)} \quad I_{sec} = \frac{I_{pri}}{CT_{CT\_ratio\_remote\_bus}}$$

$$I_{sec} = \frac{2280.6 \angle -52.8^\circ \text{ A}}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8^\circ \text{ A}$$

To satisfy the 115% margin in Options 15a and 16a:

$$\text{Eq. (170)} \quad I_{sec\ limit} > I_{sec} \times 115\%$$

$$I_{sec\ limit} > 5.701 \angle -52.8^\circ \text{ A} \times 1.15$$

$$I_{sec\ limit} > 6.56 \angle -52.8^\circ \text{ A}$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

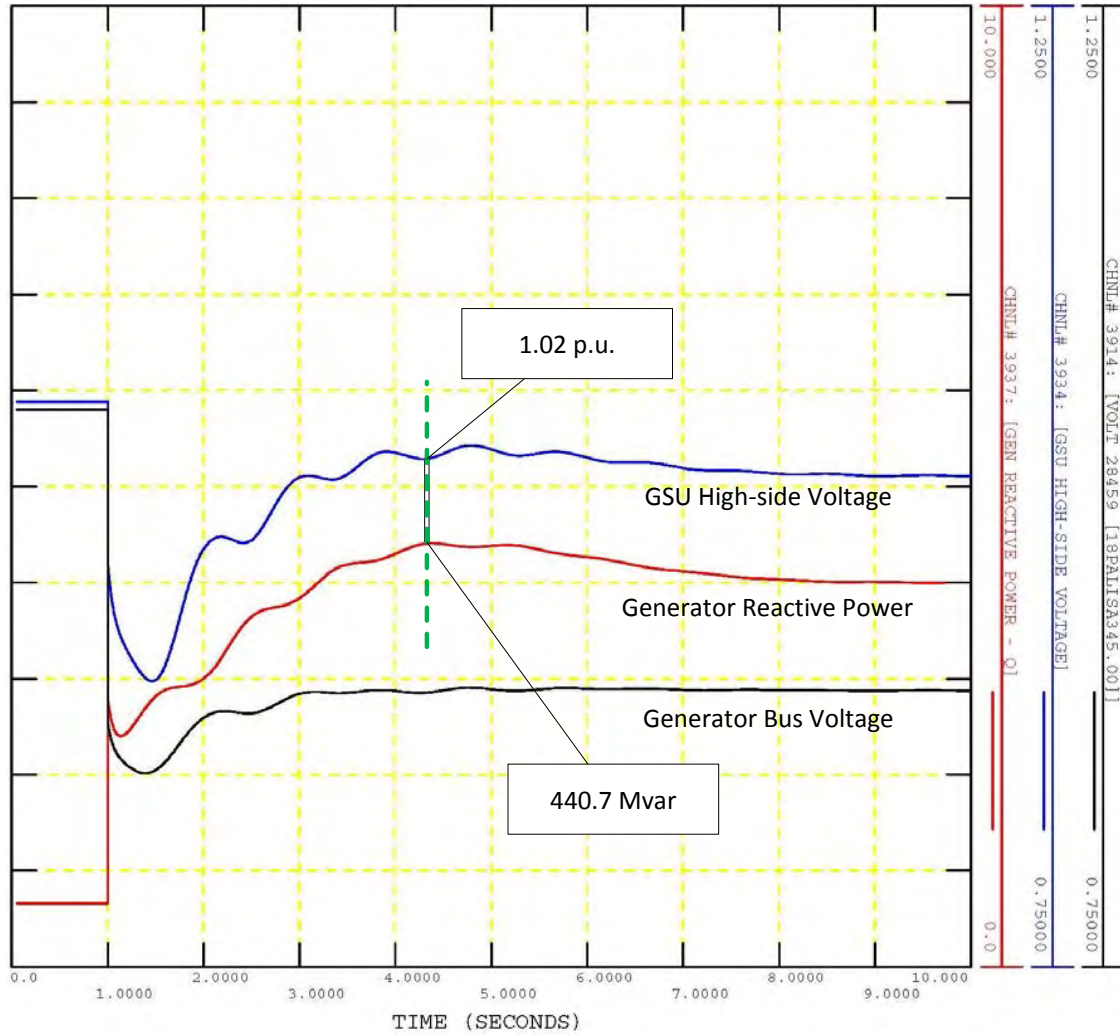
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7 \text{ Mvar}$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9 \text{ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \text{ MW}$$

Apparent power (S):

$$\text{Eq. (171)} \quad S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 15b and 16b

$$S = 700.0 \text{ MW} + j440.7 \text{ Mvar}$$

$$S = 827.2 \angle 32.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (172)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2 \angle -32.2^\circ \text{ MVA}}{1.73 \times 351.9 \text{ kV}}$$

$$I_{pri} = 1357.1 \angle -32.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (173)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1 \angle -32.2^\circ \text{ A}}{\frac{2000}{5}}$$

$$I_{sec} = 3.39 \angle -32.2^\circ \text{ A}$$

To satisfy the 115% margin in Options 15b and 16b:

$$\text{Eq. (174)} \quad I_{sec\ limit} > I_{sec} \times 115\%$$

$$I_{sec\ limit} > 3.39 \angle -32.2^\circ \text{ A} \times 1.15$$

$$I_{sec\ limit} > 3.90 \angle -32.2^\circ \text{ A}$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

$$\text{Eq. (175)} \quad P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \text{ MVA} \times 0.85$$

$$P_{Asynch} = 102.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (176)} \quad Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q_{Asynch} = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \text{ Mvar}$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

$$\text{Eq. (177)} \quad V_{bus} = 1.0 \text{ p. u.} \times V_{nom}$$

$$V_{gen} = 1.0 \times 345 \text{ kV}$$

$$V_{gen} = 345.0 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (178)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (179)} \quad Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0 \text{ kV})^2}{131.6 \angle -39.2^\circ \text{ MVA}}$$

$$Z_{pri} = 904.4 \angle 39.2^\circ \Omega$$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

$$\text{Eq. (180)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4 \angle 39.2^\circ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4 \angle 39.2^\circ \Omega \times 0.03$$

$$Z_{sec} = 27.13 \angle 39.2^\circ \Omega$$

To satisfy the 130% margin in Option 17:

$$\text{Eq. (181)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{130\%}$$

$$Z_{sec \text{ limit}} = \frac{27.13 \angle 39.2^\circ \Omega}{1.30}$$

$$Z_{sec \text{ limit}} = 20.869 \angle 39.2^\circ \Omega$$

$$\theta_{transient \text{ load angle}} = 39.2^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , and then the maximum allowable impedance reach is:

$$\text{Eq. (182)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{20.869 \Omega}{\cos(85.0^\circ - 39.2^\circ)}$$

$$Z_{max} < \frac{20.869 \Omega}{0.697}$$

$$Z_{max} < 29.941 \angle 85.0^\circ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. (183)} \quad P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \text{ MVA} \times 0.85$$

$$P = 102.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (184)} \quad Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \text{ Mvar}$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

$$\text{Eq. (185)} \quad V_{nom} = 1.0 \text{ p.u.} \times V_{nom}$$

$$V_{bus} = 1.0 \times 345 \text{ kV}$$

$$V_{bus} = 345 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (186)} \quad S = P + jQ$$

Example Calculations: Options 18 and 19

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (187)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 345 \text{ kV}}$$

$$I_{pri} = 220.5 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (188)} \quad I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5 \angle -39.2^\circ \text{ A}}{\frac{300}{5}}$$

$$I_{sec} = 3.675 \angle -39.2^\circ \text{ A}$$

To satisfy the 130% margin in Options 18 and 19:

$$\text{Eq. (189)} \quad I_{sec\ limit} > I_{sec} \times 130\%$$

$$I_{sec\ limit} > 3.675 \angle -39.2^\circ \text{ A} \times 1.30$$

$$I_{sec\ limit} > 4.778 \angle -39.2^\circ \text{ A}$$

End of calculations

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

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

A. Introduction

1. **Title:** Coordination of Protection Systems for Performance During Faults
2. **Number:** PRC-027-1
3. **Purpose:** 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.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Transmission Owner
 - 4.1.2. Generator Owner
 - 4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)
 - 4.2. **Facilities:** Protection Systems installed to detect and isolate Faults on BES Elements.
5. ~~**Effective Date:** See the Implementation Plan for PRC 027-1, Project 2007-06 System Protection Coordination.~~

B. Requirements and Measures

- R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
 - 1.1. A review and update of short-circuit model data for the BES Elements under study.
 - 1.2. A review of the developed Protection System settings.
 - 1.3. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:
 - 1.3.1. Provide the proposed Protection System settings to the owner(s) of the electrically joined Facilities.
 - 1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

- 1.3.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.
 - 1.3.4. Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.
- M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to develop settings for its Protection Systems, in accordance with Requirement R1.
- R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
 - Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
 - Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;¹ or,
 - Option 3: Use a combination of the above.
- M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.
- R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

¹ The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

- M3.** Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

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 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 Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 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 Transmission Owner, Generator Owner, or Distribution Provider 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	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

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				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – “Power Plant and Transmission System Protection Coordination.”

NERC System Protection and Control Task Force, December 7, 2006, “Assessment of Standard PRC-001-0 – System Protection Coordination.”

NERC System Protection and Control Task Force, September 2006, “The Complexity of Protecting Three-Terminal Transmission Lines.”

Version History

Version	Date	Action	Change Tracking
1	November 5, 2015	Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions² are applicable to Requirement R2 if: (1) available Fault current levels are used to develop the settings for those Protection System functions; and (2) those Protection System functions require coordination with other Protection Systems.

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions utilize current in their measurement to initiate tripping of circuit breakers. Changes in the magnitude of available Fault current can impact the coordination of these functions.
2. See the PRC-027-1 Supplemental Material section for additional information.

² ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

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Purpose

The Purpose states: 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.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current data upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

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The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of “coordination of protection” is from the pending revision of IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

“The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault.”

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for “Protection System coordination” is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the BES Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit model data for the BES Elements under study.

The short-circuit study provides the necessary Fault currents used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances and Fault currents.

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2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities.

Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

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The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years;³ or,

³ The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA). If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline by performing a Protection System Coordination Study.

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- Option 3: Use a combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six-calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which a BES Element is connected. Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. This option allows the entity to choose an interval of up to six-calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

As described in the footnote for Requirement R2, Option 2, an entity that elects to initially use Option 2 must establish its baseline prior to the effective date of the standard. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current baseline values can be updated or established when a Protection System Coordination Study is performed. The baseline values at each bus to which a BES Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject

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Protection System. The footnote also states that the Fault current baselines may be established for BES generating resources at the generator, the BES aggregation point for dispersed power producing resources, or at the common point of connection at 100 kV or above.

Example: Prior to the effective date of PRC-027-1, an entity intending to use Option 2 of Requirement R2 establishes an initial baseline; e.g., 10,000 amps at the bus to which the BES Element under study is connected. A short-circuit review performed on March 1, 2024, for example, identifies that the Fault current has increased to 11,250 amps (12.5 percent deviation); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next comparison (to be performed no later than December 31, 2030) remains at 10,000 amps because no study was required as a result of the initial comparison. During the next six-year interval, Fault current comparison identifies that the Fault current has increased to 11,500 (15 percent deviation); therefore, a Protection System Coordination Study is required (and must also be completed no later than December 31, 2030), and a new baseline of 11,500 amps would be established.

Note: In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six-calendar-year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

The Protection System functions listed in Attachment A utilize AC current in their measurement to initiate tripping of circuit breakers and the coordination of these functions is susceptible to changes in the magnitude of available short-circuit Fault current. These functions are included in Attachment A based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. Examples of functions not included in Attachment A because they do not meet both of the criteria are differential relays and Fault detectors. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

The following provide additional information regarding the Protection System functions in Attachment A.

A “51 – AC inverse time overcurrent” relay connected to a CT on the neutral of a generator step-up transformer, referred to as “51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)” in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are “51 – AC Inverse time overcurrent” relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function used in conjunction with a “62 – Time-delay” function.

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If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed “21 – Distance” function, which is a “21 – Distance” function with a “62 – Time-delay” function. Another example would be a definite-time overcurrent function, which is a “50 – Instantaneous overcurrent” function with a “62 – Time-delay” function. A “50 – Instantaneous overcurrent” function used for supervising a “21 – Distance” function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing “21 – Distance” functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is not used in determining the setting, “21 – Distance” functions would not be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, “21 – Distance” functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

The 67 – AC directional overcurrent function utilized in Protection Systems for Transmission lines can be instantaneous overcurrent, inverse time overcurrent, or both instantaneous overcurrent and inverse time overcurrent. For example, in a communication-aided directional comparison blocking (DCB) scheme, the instantaneous overcurrent function is set very sensitive. When a single line-to-ground Fault occurs on a Transmission line, the Fault is detected by a number of Protection Systems for other Transmission lines. Signals from communication equipment are transmitted and received to block the other Protection Systems for the non-faulted Transmission lines from operating, thereby providing the coordination. A 67 – AC directional overcurrent function used in a permissive overreaching transfer trip scheme (POTT) relies on a signal from the remote end to operate and, therefore, does not require coordination with other Protection Systems.

Instantaneous overcurrent and/or inverse time overcurrent for a 67 – AC directional overcurrent function are utilized in a non-communication-aided Protection System for Transmission lines. As communication is not used to prevent operation for Faults outside a Protection System’s zone of protection, coordination is necessary with other Protection Systems for buses, transformers, and other Transmission lines. The instantaneous overcurrent function should be set to not overreach the end of the Transmission line. The inverse time overcurrent function should be set to coordinate with the inverse time overcurrent function of other Protection Systems. Changes in the magnitude of available Fault current can affect the coordination.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

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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 adoption, the text from the rationale text boxes will be moved to this section.

Rationale for Requirement R1:

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: “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.” Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit model data used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information. Generator Owners and Distribution Providers may not have or maintain short-circuit models; consequently, these entities would obtain the short-circuit model data from the Transmission Planners, Planning Coordinators, or Transmission Owners.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include provisions to communicate those

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unplanned settings changes after-the-fact to the other owner(s) of the electrically joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires Transmission Owners, Generator Owners, and Distribution Providers to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six-calendar years, a Protection System Coordination Study for each of its Protection Systems identified in Attachment A. The six-calendar-year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current-based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new BES Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators, or Transmission Owners. In a time interval not to exceed six-calendar years following the effective date of this standard, an entity must perform a Fault current comparison. If the comparison identifies a deviation less than 15 percent, no further action is required for that six-year interval; however, if the comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the BES Element is connected, the entity must also perform a Protection System Coordination Study during the same six-year interval. The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other

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business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current-based option for existing BES Elements as well as establishing baselines for new BES Elements by performing Protection System Coordination Studies. The footnote also states that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA).

Option 3 provides the entity the choice of using both the time-based and Fault current-based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current-based methodology for Protection Systems at other Facilities.

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-5
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
 - 4.1. Transmission Operators
 - 4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

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

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

B. Requirements and Measures

- R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- 1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.
- M1.** The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.
- For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.
- R2.** Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*
- M2.** Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.
- R3.** Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*
- M3.** Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.
- R4.** Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target

value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

- R6.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M6.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to 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 a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6	Operations Planning	Lower	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

- E.A.13** Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- A voltage set point with a voltage tolerance band and a specified period.
 - An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
 - A voltage band for a specified period.
- M.E.A.13** Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.
- E.A.14** Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- The generator terminals.
 - The high side of the generator step-up transformer.
 - The point of interconnection.
 - A location designated by mutual agreement between the Transmission Operator and Generator Operator.
- M.E.A.14** The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.
- E.A.15** Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals

within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M.E.A.15** The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.
- E.A.16** Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M.E.A.16** The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.
- E.A.17** Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- E.A.17.1** Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.
- E.A.17.2.** Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.
- M.E.A.17** If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator will have evidence that it met the control loop specifications in sub-parts E.A.17.1 through E.A.17.2, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design specifications with identified agreed-upon control loops, system reports, or other dated documentation.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.15	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.16	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.17	N/A	The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 10, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	
5	August 16, 2018	Adopted by NERC Board of Trustees	1) In E.A.14 “Area” was changed to

			“area.”; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing “shall” with “will”; 4) typographical errors in VSL Table for E.A.17 were corrected; 5) format was updated.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

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

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

**Mandatory Reliability Standards
Assessment Report No. 12**

Appendix A-2

Reliability Standards Assessed by BC Hydro

Red-lined

BAL-002-~~32~~ – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-~~32~~
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**
 - 4.1. **Responsible Entity**
 - 4.1.1. Balancing Authority
 - 4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.
 - 4.1.2. Reserve Sharing Group
5. **Effective Date:** See the Implementation Plan for BAL-002-~~32~~.

~~6. **Background:**~~

~~Reliably balancing an interconnection requires frequency management and all of its aspects. Inputs to frequency management include Tie-Line Bias Control, Area Control Error (ACE), and the various Requirements in NERC Resource and Demand Balancing Standards, specifically BAL-001-2 Real Power Balancing Control Performance and BAL-003-1 Frequency Response and Frequency Bias Setting.~~

B. Requirements and Measures

- R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:
[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Real-time Operations]
 - 1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:
 - zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,
 - or,
 - its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing

Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

- 1.2. document all Reportable Balancing Contingency Events using CR Form 1.
- 1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

~~1.3.1 the Responsible Entity:~~

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level~~or is a Reserve Sharing Group whose member, or members, are 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, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement

an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning]*

- M2.** Each Responsible Entity will have the following documentation to show compliance with Requirement R2:
- a dated Operating Process;
 - evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
 - evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.
- R3.** Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*
- M3.** Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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, 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 ~~the NERC~~ 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 Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous calendar years, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer

period of time as part of an investigation.

If a Responsible Entity is found noncompliant, it shall keep information related to the noncompliance until found compliant, or for the time period specified above, whichever is longer.

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

1.3. 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

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Time-Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	Real-time Operations	Medium	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

~~BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event~~

R2.	~~Operations Planning~~	~~Medium~~	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

~~BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event~~

R3	Real-time Operations	Medium	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

[CR Form 1](#)

[BAL-002-3 Rationales](#)

[BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event](#)

~~BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event~~

[Supplemental Material](#)

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

~~CR Form 1~~

BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from -Effective Date	Errata
0	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
<u>2</u>	<u>January 19, 2017</u>	<u>FERC Order approved BAL-002-2. Docket No. RM16-7-000</u>	
<u>2</u>	<u>October 2, 2017</u>	<u>FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.</u>	
<u>3</u>	<u>August 16, 2018</u>	<u>Adopted by NERC Board of Trustees</u>	<u>Revisions to address two FERC directives from Order No. 835</u>
<u>3</u>	<u>September 25, 2018</u>	<u>FERC Order approving BAL-002-3. Docket No. RD18-7-000</u>	

Supplemental Material

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 adoption, the text from the rationale text boxes was moved to this section.

Rationale for Requirement R1:

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller BA's and RSGs in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

Finally, commenters have suggested that the language in R1 part 1.3 be changed to specifically state under which EEA level the exclusion applies. The drafting team disagrees with this proposal. NERC is in the process of changing the EEA levels and what is expected in each level. The current EEA levels suggest that when an entity is experiencing an EEA Level 2 or 3 it is short of Contingency Reserves as normally defined to exclude readiness to curtail a specific amount of Firm Demand. Under the proposed EEA process, this would only be during an EEA Level 3. In order to reduce the need for consequent modifications of the BAL-002 standard, the drafting team has developed the proposed language in Requirement 1 Part 1.3.1 such that it addresses both current and future EEA process. In addition, the drafting team has added some clarifying language to 1.3.1 since comments were presented in previous postings expressing a concern only a Balancing Authority may request declaration of an EEA and a RSG cannot request an EEA. The standard drafting team's intent has always been if a BA is experiencing an EEA event under

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~~which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.~~

Rationale for Requirement R2:

~~R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.~~

Rationale for Requirement R3:

~~This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.~~

~~* FOR INFORMATIONAL PURPOSES ONLY *~~

~~Enforcement Dates: Standard BAL-002-2 — Disturbance Control Standard — Contingency Reserve for Recovery from a Balancing Contingency Event~~

United States

Standard	Requirement	Enforcement Date	Inactive Date
BAL-002-2	All	01/01/2018	

~~Printed On: March 09, 2017, 03:25 AM~~

A. Introduction

- 1. Title:** Automatic Time Error Correction
- 2. Number:** BAL-004-WECC-032
- 3. Purpose:** To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.

4. Applicability

4.1. Functional Entities

- 4.1.1** Balancing Authorities that operate synchronously in the Western Interconnection.

- 5. Effective Date:** On the first day of the second quarter, after applicable regulatory approval has been received (or the Reliability Standard otherwise becomes effective the first day of the fourth quarter following NERC Board adoption where regulatory approval is not required).

6. Background:

In February 2003, the WECC Automatic Time Error Correction (ATEC) Procedure (Procedure) became effective for all Balancing Authorities in the Western Interconnection. The original intent of the Procedure was to minimize the number of Manual Time Error Corrections in the Western Interconnection. ATEC provides the added benefit of a superior approach over the current NERC Reliability Standard BAL-004-0 – Time Error Correction for assigning costs and providing for the equitable payback of Inadvertent Interchange. In October 2006, the Procedure became a WECC Criterion. In May 2009, FERC issued Order No.723 that approved Regional Reliability Standard BAL-004-WECC-1 - Automatic Time Error Correction, as submitted by NERC. In addition, the Commission directed WECC to develop several clarifying modifications to BAL-004-WECC-1 using the FERC-approved Process for Developing and Approving WECC Standards. The Effective Date of the BAL-004-WECC-1 standard was July 1, 2009. BAL-004-WECC-1 required Balancing Authorities within the Western Interconnection to maintain Interconnection frequency within a predefined frequency profile and to ensure that Time Error Corrections were effectively conducted in a manner that did not adversely affect the reliability of the Interconnection. In September 2009, WECC received WECC Standards/Regional Criterion Request Form (Request) WECC-0068, which was a request for modification of BAL-004-WECC-1. In July 2010, the chair of the WECC Operating Committee assigned the Request to the Performance Work Group (PWG) for development.

B. Requirements and Measures

~~R1. Following the conclusion of each month each Balancing Authority shall verify that the absolute value of its Accumulated Primary Inadvertent Interchange (PII_{accum}) for both the monthly On-Peak period and the monthly Off-Peak period are each individually less than or equal to:~~

~~1.1. For load-serving Balancing Authorities, 150% of the previous calendar year's integrated hourly Peak Demand,~~

~~1.2. For generation-only Balancing Authorities, 150% of the previous calendar year's integrated hourly peak generation.~~

~~[Violation Risk Factor Medium:] [Time Horizon: Operations Assessment]~~

~~M1. Forms of acceptable evidence of compliance with Requirement R1 include but are not limited to any one of the following:~~

- ~~• Data, screen shots from the WECC Interchange Tool (WIT),~~
- ~~• Data, screen shots from the internal Balancing Authority tool, or~~
- ~~• Production of data from any other databases, spreadsheets, displays.~~

R1. Each Balancing Authority shall operate its system such that the month-end absolute value of its On-Peak and Off-Peak, Accumulated Primary Inadvertent Interchange (PII_{accum}), occurring after hour ending 23 (HE23) and prior to any month-end corrections, as calculated by the Reliability Coordinator's Interchange software, meets the following criteria: [Violation Risk Factor Medium:] [Time Horizon: Operations Assessment]

1.1 Is less than or equal to the greater of either 500 MWh or $60 * L_{10}$, expressed in MWh, for the Balancing Authority Area.

M1. THE MEASURE WILL BE UPDATED AFTER THE REQUIREMENT IS FINALIZED.

R2. Each Balancing Authority shall, upon discovery of an error in the calculation of PII_{hourly} , recalculate within 90 days, the value of PII_{hourly} and adjust the PII_{accum} from the time of the error. [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

M2. Forms of acceptable evidence of compliance with Requirement R2 include but are not limited to any one of the following:

- Data, screen shots from the WIT,
- Data, screen shots from the internal Balancing Authority tool, or
- Production of data from any other databases, spreadsheets, displays.

R3. Each Balancing Authority shall keep its Automatic Time Error Correction (ATEC) in service, with an allowable exception period of less than or equal to an accumulated 24

WECC Standard BAL-004-WECC-032 — Automatic Time Error Correction

hours per calendar quarter for ATEC to be out of service. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations]*

M3. Forms of acceptable evidence of compliance with Requirement R3 may include, but are not limited to:

- Dated archived files,
- Historical data,

- Other data that demonstrates the ATEC was out of service for less than 24 hours per calendar quarter.

R4. Each Balancing Authority shall compute the following by 50 minutes after each hour:

- 4.1.** PII_{hourly} ,
- 4.2.** PII_{accum} ,
- 4.3.** Automatic Time Error Correction term (I_{ATEC}).

[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]

M4. Forms of acceptable evidence of compliance with Requirement R4 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from internal Balancing Authority tool that demonstrate compliance, or
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

R5. Each Balancing Authority shall be able to change its Automatic Generation Control operating mode between Flat Frequency (for blackout restoration); Flat Tie Line (for loss of frequency telemetry); Tie Line Bias; and Tie Line Bias plus Time Error Control (used in ATEC mode), to correspond to current operating conditions. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

M5. Forms of acceptable evidence of compliance with Requirement R5 include but are not limited to any one of the following:

- Screen shots from Energy Management System,
- Demonstration using an off-line system.

R6. Each Balancing Authority shall recalculate the PII_{hourly} and PII_{accum} for the On-Peak and Off-Peak periods whenever adjustments are made to hourly Inadvertent Interchange or ΔTE . *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M6. Forms of acceptable evidence of compliance with Requirement R6 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,

- Data, screen shots from an internal Balancing Authority tool that demonstrate compliance with, or
- Data from any other databases, spreadsheets, displays that demonstrate compliance.

R7. Each Balancing Authority shall make the same adjustment to the PII_{accum} as it did for any month-end meter reading adjustments to Inadvertent Interchange. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M7. Forms of acceptable evidence of compliance with Requirement R7 include but are not limited to any one of the following:

- Data, screen shots from the WECC Interchange Tool that demonstrate compliance,
- Data, screen shots from an internal Balancing Authority tool that demonstrate compliance,
- Production of data from any other databases, spreadsheets, displays that demonstrate compliance.

R8. Each Balancing Authority shall payback Inadvertent Interchange using ATEC rather than bilateral and unilateral payback. *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M8. Forms of acceptable evidence of compliance with Requirement R8 include but are not limited to historical On-Peak and Off-Peak Inadvertent Interchange data, data from the WECC Interchange Tool, and ACE data.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority.

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For Reliability Coordinators and other functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

For responsible entities that are also Regional Entities, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

1.2 Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3 Evidence Retention

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

Each Balancing Authority in the Western Interconnection shall retain the values of PII_{hourly} , PII_{accum} (On-Peak and Off-Peak), ΔTE and any month-end adjustments for the preceding calendar year (January – December), as well as the current calendar year.

Each Balancing Authority in the Western Interconnection shall retain the amount of time the Balancing Authority operated without ATEC for the preceding calendar year (January – December), as well as the current calendar year.

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	Operations Assessment	Medium	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 150%, but was less than or equal to 160% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 160%, but was less than or equal to 170% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 170%, but was less than or equal to 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.	Following the conclusion of each month each Balancing Authority's absolute value of PII_{accum} for either the On-Peak period or Off-Peak period exceeded 180% of the previous calendar year's Peak Demand or peak generation for generation-only Balancing Authorities.
R2	Operations Assessment	Medium	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 90 days of the discovery of the error; but made the required recalculations and adjustments within 120 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 120 days of the discovery of the error; but made the required recalculations and adjustments within 150 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust the PII_{accum} within 150 days of the discovery of the error; but made the required recalculations and adjustments within 180 days.	The Balancing Authority did not recalculate PII_{hourly} and adjust PII_{accum} within 180 days of the discovery of the error.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Real-Time Operations	Medium	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 24 hours, but less than or equal to 72 hours.	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 72 hours, but less than or equal to 120 hours.	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 120 hours, but less than or equal to 168 hours	The Balancing Authority operated during a calendar quarter without ATEC in service for more than an accumulated 168 hours.
R4	Operations Assessment	Medium	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within 50 minutes, but made the required calculations in less than or equal to two hours.	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within two hours, but made the required calculations in less than or equal to four hours.	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within four hours, but made the required calculations in less than or equal to six hours.	The Balancing Authority did not compute PII_{hourly} , PII_{accum} , and I_{ATEC} within six hours.
R5	Real-Time Operations	Medium	N/A	N/A	N/A	The Balancing Authority is not able to change its AGC operating mode between Flat Frequency (for blackout restoration; Flat Tie Line (for loss of frequency

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						telemetry); Tie Line Bias; or Tie Line Bias plus Time Error control (used in ATEC mode).
R6	Operations Assessment	Medium	N/A	N/A	N/A	When making adjustments to hourly Inadvertent Interchange or ΔTE , the Balancing Authority did not recalculate the PII_{hourly} and the PII_{accum} for the On-Peak and Off-Peak periods.
R7	Operations Assessment	Medium	N/A	N/A	N/A	When making any month-end meter reading adjustments to Inadvertent Interchange, the Balancing Authority did not make the same adjustment to the PII_{accum} .
R8	Operations Assessment	Medium	N/A	N/A	N/A	The Balancing Authority paid back Inadvertent

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R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Interchange using bilateral and unilateral payback rather than using ATEC.

Guidelines and Technical Basis

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.

Requirement R1:

Premise: Each Balancing Authority should ensure that the absolute value of its PII_{accum} for both the On-Peak period and the Off-Peak period each individually does not exceed 150% of the previous year's Peak Demand for load-serving Balancing Authorities and 150% of the previous year's peak generation for generation-only Balancing Authorities. The Balancing Authority is required to take action to keep each PII_{accum} period within the limit. For example, the Balancing Authorities actions may include:

- Identifying and correcting the source of any metering or accounting error(s) and recalculating the hourly Primary Inadvertent Interchange (PII_{hourly}) and the PII_{accum} from the time of the error;
- Validating the implementation of ATEC; or
- Setting L_{max} equal to L_{10} until the PII_{accum} is below the limit in Requirement R1.

Justification: PII_{accum} may grow from month-end adjustments and metering errors, even with the inclusion of I_{ATEC} in the ACE equation.

Goal: To limit the amount of PII_{accum} that a Balancing Authority can have at the end of each month.

Requirement R2:

Premise: When a Balancing Authority finds an error in the calculation of its PII, the Balancing Authority needs time to correct the error and recalculate PII and PII_{accum} .

Justification: The drafting team selected 90 days as a reasonable amount of time to correct an error and recalculate PII and PII_{accum} , since recalculation of PII and PII_{accum} is not a real-time operations reliability issue.

Goal: To promote the timely correction of errors in the calculation of PII and PII_{accum} .

Requirement R3:

Premise: When a Balancing Authority is not participating in ATEC, payback of PII_{accum} is delayed.

Justification: The limit of 24 hours per quarter discourages a Balancing Authority from withdrawing ATEC participation, for example, for economic gain during selected hours. If the limits were increased to 60 hours, a Balancing Authority could technically withdraw ATEC participation for one hour from Monday to Friday.

Goal: To promote fair and timely payback of PII_{accum} balances.

Requirement R4:

Premise: PII_{hourly} , PII_{accum} , and I_{ATEC} should be determined before the next scheduling hour begins.

Justification: To promote timely calculations 50 minutes was selected because it is before the next hour ramp begins and permits time to collect the data and resolve interchange metering values.

Goal: To promote the timely calculation of PII_{hourly} , PII_{accum} , and I_{ATEC} .

Requirement R5:

Premise: The ACE equation, and hence the AGC mode, will contain any number of parameters based on system operating conditions. Various AGC modes are identified corresponding to those operating conditions, as well as the specific sets of parameters included in the ACE equation.

Justification: Changing to the proper operating mode, corresponding to current operating conditions, affords proper movement of generating units in response to those conditions. The addition of the ATEC term results in an additional AGC mode and a different set of parameters. The inability to correctly calculate the ATEC term would dictate that AGC not be operated in the ATEC mode.

Goal: To set the AGC mode and calculate ACE in a manner that corresponds to the system operating conditions and to accommodate changes in those conditions.

Requirement R6:

Premise: Hourly adjustments to hourly Inadvertent Interchange (II) require a recalculation of the corresponding hourly PII value, the corresponding PII_{accum} , and all subsequent PII_{accum} for every hour up to the current hour.

Justification: As PII_{hourly} is corrected, then PII_{accum} should be recalculated.

Goal: To promote accurate, fair and timely payback of accumulated PII balances.

Requirement R7:

Premise: Month-end meter-reading adjustments are made, for example, when a Balancing Authority performs monthly comparisons of recorded month-end Net Actual Interchange (NI_A) values derived from hourly Actual Interchange Telemetered Values against month-end Actual Interchange Register Meter readings.

Justification: Month-end adjustments to II_{accum} are applied as 100% PII_{accum} . 100% was chosen for simplicity to bilaterally assign PII_{accum} to both Balancing Authorities, since the effect of this metering error on system frequency is not easily determined over the course of a month.

Goal: To provide a mechanism by which corresponding month-end II adjustments can be applied to Pll_{accum} , when such adjustments cannot be attributed to any one particular hour or series of hours.

Requirement R8:

Premise: ATEC includes automatic unilateral payback of Primary Inadvertent Interchange and Secondary Inadvertent Interchange.

Justification: Additional unilateral and bilateral exchanges disturb the balance and distribution between Primary Inadvertent Interchange and Secondary Inadvertent Interchange throughout the Interconnection; thereby stranding Secondary Inadvertent Interchange.

Goal: To not strand Secondary Inadvertent Interchange.

Version History

Version	Date	Action	Change Tracking
1	February 4, 2003	Effective Date.	New
1	October 17, 2006	Created Standard from Procedure.	Errata
1	February 6, 2007	Changed the Standard Version from 0 to 1 in the Version History Table.	Errata
1	February 6, 2007	The upper limit bounds to the amount of Automatic Time Error Correction term was inadvertently omitted during the Standard Translation. The bound was added to the requirement R1.4.	Errata
1	February 6, 2007	The statement “The Time Monitor may declare offsets in 0.001-second increments” was moved from TEoffset to TDadj and offsets was corrected to adjustments.	Errata
1	February 6, 2007	The reference to seconds was deleted from the TE offset term.	Errata
1	June 19, 2007	The standard number BAL-STD-004-1 was changed to BAL-004-WECC-01 to be consistent with the NERC Regional Reliability Standard Numbering Convention.	Errata
2	December 19, 2012	Adopted by NERC Board of Trustees	
2	October 16, 2013	A FERC Letter Order was issued on October 16, 2013, approving BAL-004-WECC-02. This standard will become enforceable on April 1, 2014.	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard BAL-004-WECC-02 — Automatic Time Error Correction

United States

Standard	Requirement	Enforcement Date	Inactive Date
BAL-004-WECC-02	All	04/01/2014	

Printed On: September 26, 2016, 05:35 PM

A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-~~5~~7
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the ~~BES~~Bulk Electric System (BES).
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Special Protection System (SPS) or Remedial Action Scheme (RAS) where the ~~Special Protection System~~SPS or ~~Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3. **Generator Operator**
 - 4.1.4. **Generator Owner**
 - 4.1.5. **Interchange Coordinator or Interchange Authority**
 - 4.1.6. **Reliability Coordinator**

4.1.7. Transmission Operator

4.1.8. Transmission Owner

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

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

4.2.1.2. Each ~~Special Protection System~~SPS or ~~Remedial Action Scheme~~RAS where the ~~Special Protection System~~SPS or ~~Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

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

4.2.3. Exemptions: The following are exempt from Standard CIP-003-~~57~~:

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

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

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant

~~CIP-003-5 — Cyber Security — Security Management Controls~~~~CIP-003-7 - Cyber Security — Security Management Controls~~

to 10 C.F.R. Section 73.54.

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

5. Effective Dates:

- ~~1. **24 Months Minimum** — CIP-003-5, except for CIP-003-5, Requirement R2, shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval. CIP-003-5, Requirement R2 shall become effective on the later of July 1, 2016, or the first calendar day of the 13th calendar quarter after the effective date of the order providing applicable regulatory approval.~~
- ~~2. In those jurisdictions where no regulatory approval is required, CIP-003-5, except for CIP-003-5, Requirement R2, shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, and CIP-003-5, Requirement R2 shall become effective on the first day of the 13th calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

See Implementation Plan for CIP-003-7.

6. Background:

Standard CIP-003-~~5~~ exists as part of a suite of CIP Standards related to cyber security. ~~CIP-002-5 requires, which require~~ the initial identification and categorization of BES Cyber Systems. ~~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 require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the Version 5 CIP Cyber Security Standards.~~

~~The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on whether there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:~~

~~Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, ...~~

The term policy refers to one or a collection of written documents that are used to communicate the Responsible Entities' management goals, objectives and expectations for how the Responsible Entity will protect its BES Cyber Systems. The use of policies also establishes an overall governance foundation for creating a culture of security and compliance with laws, regulations, and standards.

The term documented processes refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. -This term does not imply any naming

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or approval structure beyond what is stated in the requirements. -An entity should include as much as it believes necessary in ~~their~~its documented processes, but ~~they~~it must address the applicable requirements. ~~The documented processes themselves are not required to include the "... identifies, assesses, and corrects deficiencies, ..." elements described in the preceding paragraph, as those aspects~~

~~are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.~~

The terms program and plan are sometimes used in place of documented processes where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as plans (i.e., incident response plans and recovery plans). -Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term program may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. -Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Reliability Standards could also be referred to as a program. However, the terms program and plan do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high ~~and~~, medium, and low impact BES Cyber Systems. For example, a single ~~training~~cyber security awareness program could meet the requirements ~~for training personnel~~ across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

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Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the ~~Bulk Electric System~~ BES. A review of UFLS tolerances defined within ~~regional reliability standards~~ Regional Reliability Standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

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

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

- 1.1.1.** Personnel ~~&and~~ training (CIP-004);
- 1.1.2.** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
- 1.1.3.** Physical security of BES Cyber Systems (CIP-006);
- 1.1.4.** System security management (CIP-007);
- 1.1.5.** Incident reporting and response planning (CIP-008);
- 1.1.6.** Recovery plans for BES Cyber Systems (CIP-009);
- 1.1.7.** Configuration change management and vulnerability assessments (CIP-010);
- 1.1.8.** Information protection (CIP-011); and
- 1.1.9.** Declaring and responding to CIP Exceptional Circumstances.

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

- 1.2.1.** Cyber security awareness;
- 1.2.2.** Physical security controls;
- 1.2.3.** Electronic access controls;
- 1.2.4.** Cyber Security Incident response;
- 1.2.5.** Transient Cyber Assets and Removable Media malicious code risk mitigation; and
- 1.2.6.** Declaring and responding to CIP Exceptional Circumstances.

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

R2. Each Responsible Entity ~~for its assets with at least one asset~~ identified in CIP-002-5, ~~Requirement R1, Part R1.3, containing low impact BES Cyber Systems~~ shall implement, ~~in a manner that identifies, assesses, and corrects deficiencies,~~ one or more documented cyber security ~~policies that collectively address~~ plan(s) for its low impact BES Cyber Systems that include the following topics, and review and obtain CIP Senior Manager

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~~approval for those policies at least once every 15 calendar months; sections in Attachment 1.~~

~~[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

~~1.1.10.1.1.1. Cyber security awareness;~~

~~1.1.11.1.1.1. Physical security controls;~~

~~2.1 Electronic access controls for external routable protocol connections and Dial up Connectivity; and~~

~~2.1 Incident response to a Cyber Security Incident.~~

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

~~M2. Examples of evidence may Evidence shall include, but are not limited to, one or more, each of the documented cyber security policies and evidence of processes, procedures, or plans plan(s) that collectively include each of the sections in Attachment 1 and additional evidence to demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy plan(s). Additional examples of evidence per section are located in Attachment 2.~~

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

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

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

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

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C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

~~The Regional Entity shall serve as~~As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority (~~“”~~ (CEA) ~~unless~~) means NERC or the applicable entity is owned, operated, or controlled by Regional Entity in their respective roles of monitoring and enforcing compliance with the Regional Entity. ~~In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA~~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 Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance ~~Audit~~Audits
- Self-~~Certification~~Certifications
- Spot Checking
- Compliance ~~Investigation~~Investigations
- Self-Reporting
- ~~Complaint~~
- Complaints

1.4. Additional Compliance Information:

None.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~52~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1.<u>1</u>) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did-	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1.<u>1</u>) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did-	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1.<u>1</u>) OR The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18-~~calendar months of the~~	The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1.<u>1</u>) OR The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1.<u>1</u>) OR ~~The Responsible~~

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~5,7~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<u>complete this review</u> in less than or equal to 16 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager ~~or delegate~~ within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of the previous approval. (R1.1)	<u>complete this review</u> in less than or equal to 17 calendar months of the previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager ~~or delegate~~ within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of the previous approval. (R1.1)	~~calendar months of the~~ previous review. (R1.1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager ~~or delegate~~ within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1) OR <u>The Responsible Entity documented one or more cyber security policies for its assets identified in CIP-002 containing low impact</u>	<u>The Responsible</u> Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1) OR The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager ~~or delegate~~ within 18 calendar months of the previous approval. (R1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-62)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						(R1)
R2	Operations- Planning	Lower	<u>OR</u> The Responsible Entity documented ~~and implemented~~ one or more cyber security policies for ~~its~~ assets ~~with~~ ~~identified in CIP-002~~ containing low impact ~~rating that~~ <u>BES Cyber Systems, but did not</u> address ~~only three~~ <u>one</u> of the <u>six</u> topics ~~as required by R2 and has identified deficiencies but did not assess or correct the deficiencies.~~ ~~(R2R1. (R1.2))~~ OR The Responsible Entity ~~documented and implemented~~ <u>did not complete its review of the</u> one or more ~~documented~~	<u>OR</u> The Responsible Entity documented ~~and implemented~~ one or more cyber security policies for ~~its~~ assets ~~with~~ ~~identified in CIP-002~~ containing low impact ~~rating that~~ <u>BES Cyber Systems, but did not</u> address ~~only two~~ <u>of the six</u> topics ~~as required by R2 and has identified deficiencies but did not assess or correct the deficiencies.~~ ~~(R2R1. (R1.2))~~ OR The Responsible Entity ~~documented and implemented~~ <u>did not complete its review of the</u> one or more ~~documented~~ cyber security	<u>BES Cyber Systems, but did not address three of the six topics required by R1. (R1.2)</u> <u>OR</u> The Responsible Entity ~~documented and implemented~~ <u>did not complete its review of the</u> one or more ~~documented~~ cyber security policies for ~~its~~ assets ~~with~~ ~~identified in CIP-002~~ containing low impact ~~rating that~~ <u>address only one of the topics</u> <u>BES Cyber Systems</u> as required by ~~R2 and has identified deficiencies~~ <u>R1 within 17 calendar months</u> but did ~~not assess~~ <u>complete this review in less than</u> or ~~correct the deficiencies.~~ ~~(R2 equal to 18 calendar months of the previous review. (R1.2))~~	<u>OR</u> The Responsible Entity ~~did not document~~ <u>document ed one</u> or ~~implement anymore~~ cyber security policies for ~~its~~ assets ~~with~~ ~~identified in CIP-002~~ containing low impact ~~rating that~~ <u>BES Cyber Systems, but did not</u> address ~~four or more of the six~~ <u>topics as required by R2.</u> ~~(R2R1. (R1.2))~~ <u>OR</u> The Responsible Entity did not ~~complete its review of the one or more~~ <u>have any</u> documented cyber security policies for ~~its~~ assets ~~with~~

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-62)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~did not identify, assess, or correct the deficiencies.~~ ~~months but did complete this~~ ~~OR~~ ~~The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R2R1.2)~~ ~~OR~~ ~~OR~~ ~~The Responsible Entity did not~~	~~months but did not identify, assess, or correct the deficiencies.~~ ~~complete this~~ ~~OR~~ ~~The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R2R1.2)~~ ~~OR~~ ~~OR~~	~~assets identified in CIP-002 containing low impact BES Cyber Systems as required by Requirement R1~~ ~~OR~~ ~~The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R2)~~ ~~OR~~ ~~The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2~~	~~The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its assets with identified in CIP-002 containing low impact rating BES Cyber Systems as required by R2 Requirement R1 by the CIP Senior Manager within 18 calendar months of the previous approval. (R2R1.2)~~

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~62~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~cyber security policies for assets with a low impact rating as required by R2 to the~~	~~documented cyber security policies for assets with a low impact rating as required by R2 to the~~	~~in less than or equal to 18 calendar months of the previous approval. (R2)~~	
~~R3~~ R2	Operations Planning	~~Medium~~ Lower	The Responsible Entity ~~has identified by name a CIP Senior Manager~~ document ed its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but ~~did not~~ failed to document cyber security awareness according to Requirement R2, Attachment 1, Section 1. (R2) <u>OR</u> <u>The Responsible</u> changes to the CIP Senior Manager within 30 calendar days	The Responsible Entity ~~has identified by name a CIP Senior Manager~~ document ed its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but ~~did not~~ document changesfailed to the CIP Senior Manager within 40reinforce cyber security practices at least once every 15 calendar daysmonths according to Requirement R2, Attachment 1, Section 1. (R2) <u>OR</u>	The Responsible Entity ~~has identified by name a CIP Senior Manager~~ document ed the physical access controls for its assets containing low impact BES Cyber Systems, but ~~did not~~ document changesfailed to the CIP Senior Manager within 50 calendar daysimplement the physical security controls according to Requirement R2, Attachment 1, Section 2. (R2) <u>OR</u> The Responsible Entity documented its cyber security plan(s) for electronic access	The Responsible Entity ~~has not identified, by name, a CIP Senior Manager.~~ <u>OR</u> <u>failed to</u> ~~The Responsible Entity~~ has identified by name a CIP Senior Manager, but ~~did not~~ document changes to the CIPand implement one or more cyber security plan(s) for its assets containing low impact BES Cyber Systems according to Requirement R2, Attachment 1. (R2)

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~5,7~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~the change. (R3)~~		~~Senior Manager within 60 calendar days of the change. (R3)~~

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R4	Operations- Planning	Lower	<u>Attachment 1, Section 3. (R2)</u> <u>OR</u> The Responsible Entity ~~has identified a delegate by name, title, date of delegation, and specific actions delegated~~<u>document ed its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but did not failed to document changes to the delegate one or more Cyber Security Incident response plan(s) according to Requirement R2, Attachment 1, Section 4. (R2)</u> <u>OR</u>	<u>to document physical security controls according to Requirement R2, Attachment 1, Section 2. (R2)</u> <u>OR</u> The Responsible Entity ~~has identified a delegate by name, title, date of delegation, and specific actions delegated~~<u>document ed its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but did not document changes to the delegate within 40 calendar days but did failed to document this change in less than 50 calendar days of</u>	<u>access controls according to Requirement R2, Attachment 1, Section 3.1. (R2)</u> <u>OR</u> <u>The Responsible Entity</u> ~~The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a process to delegate actions from the CIP Senior Manager, and has Identified deficiencies but did not assess or correct the deficiencies.(R4)~~ <u>OR</u> ~~The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a process to delegate actions from the CIP Senior Manager,~~	The Responsible Entity ~~has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4)~~ <u>OR</u> ~~The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the~~

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-003- ~~5~~ 7)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<u>low impact BES Cyber Systems, but failed to update each Cyber Security Incident response plan(s) within 180 days according to Requirement R2, Attachment 1, Section 4. (R2)</u> OR <u>The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to Requirement R2, Attachment 1, Section 5.1. (R2)</u> OR <u>The Responsible Entity documented</u>	<u>failed to implement authentication for all Dial-up Connectivity that provides access to low impact BES Cyber System(s), per Cyber Asset capability according to Requirement R2, Attachment 1, Section 3.2 (R2)</u> OR <u>The Responsible Entity documented one or more incident response plan(s) within its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to include the process for identification, classification, and response to Cyber Security Incidents</u>	~~correct the deficiencies. (R4)~~ <u>whether an identified Cyber Security Incident is a Reportable Cyber Security Incident, but failed to notify the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2, Attachment 1, Section 4. (R2)</u> OR <u>The Responsible Entity has identified a delegate by name, title, date of delegation, documented its plan(s) for Transient Cyber Assets and specific actions- delegated Removable Media, but did not document changes failed to implement mitigation for the delegate within-</u>	~~change. (R4)~~

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<u>R.#</u>	<u>Time Horizon</u>	<u>VRE</u>	<u>Violation Severity Levels (CIP-003-7)</u>			
			<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
			its plan(s) for Transient Cyber Assets, but failed to document the Removable Media section(s) according to Requirement R2, Attachment 1, Section 5.3. (R2)	according to Requirement R2, Attachment 1, Section 4. (R2) OR The Responsible Entity documented its cyber security plan(s) for its assets containing low impact BES Cyber Systems, but failed to document the determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the Electricity Information Sharing and Analysis Center (E-ISAC) according to Requirement R2,	Attachment 1, Section 5.1. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement mitigation for	

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<u>R.#</u>	<u>Time Horizon</u>	<u>VRE</u>	<u>Violation Severity Levels (CIP-003-7)</u>			
			<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
				<u>Attachment 1, Section 4. (R2)</u> <u>OR</u> <u>The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by the Responsible Entity according to Requirement R2, Attachment 1, Sections 5.1 and 5.3. (R2)</u> <u>OR</u> <u>The Responsible Entity documented its plan(s) for Transient Cyber</u>	<u>the threat of detected malicious code on the Removable Media prior to connecting Removable Media to a low impact BES Cyber System according to Requirement R2, Attachment 1, Section 5.3. (R2)</u>	

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<u>R.#</u>	<u>Time Horizon</u>	<u>VRE</u>	<u>Violation Severity Levels (CIP-003-7)</u>			
			<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
				<u>Assets and Removable Media, but failed to document mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to Requirement R2, Attachment 1, Section 5.2. (R2)</u> <u>OR</u> <u>The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media section(s) according to Requirement R2,</u>		

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<u>R.#</u>	<u>Time Horizon</u>	<u>VRE</u>	<u>Violation Severity Levels (CIP-003-7)</u>			
			<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
				Attachment 1, Section 5.3. (R2)		
<u>R3</u>	<u>Operations Planning</u>	<u>Medium</u>	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this change in less than 40 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did document this change in less than 50 calendar days of the change. (R3)	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in less than 60 calendar days of the change. (R3)	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
<u>R4</u>	<u>Operations Planning</u>	<u>Lower</u>	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process

~~CIP-003-5 — Cyber Security — Security Management Controls~~~~CIP-003-7 - Cyber Security — Security Management Controls~~

<u>R.#</u>	<u>Time Horizon</u>	<u>VRE</u>	<u>Violation Severity Levels (CIP-003-7)</u>			
			<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
			<u>not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)</u>	<u>not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)</u>	<u>within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)</u>	<u>to delegate actions from the CIP Senior Manager. (R4)</u> <u>OR</u> <u>The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 60 calendar days of the change. (R4)</u>

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

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

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

Attachment 1

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

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

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

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

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

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

- 3.1** Permit only necessary inbound and outbound electronic access as determined by the Responsible Entity for any communications that are:
 - i. between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s);
 - ii. using a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and
 - iii. not used for time-sensitive protection or control functions between intelligent electronic devices (e.g., communications using protocol IEC TR-61850-90-5 R-GOOSE).
- 3.2** Authenticate all Dial-up Connectivity, if any, that provides access to low impact BES Cyber System(s), per Cyber Asset capability.

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

- 4.1** Identification, classification, and response to Cyber Security Incidents;
- 4.2** Determination of whether an identified Cyber Security Incident is a Reportable Cyber Security Incident and subsequent notification to the

Electricity Information Sharing and Analysis Center (E-ISAC), unless prohibited by law;

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

4.4 Incident handling for Cyber Security Incidents;

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

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

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

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

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

5.2 For Transient Cyber Asset(s) managed by a party other than the Responsible Entity, if any, the use of one or a combination of the following prior to connecting the Transient Cyber Asset to a low impact BES Cyber System (per Transient Cyber Asset capability):

- Review of antivirus update level;
- Review of antivirus update process used by the party;
- Review of application whitelisting used by the party;
- Review use of live operating system and software executable only from read-only media;
- Review of system hardening used by the party; or
- Other method(s) to mitigate the introduction of malicious code.

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

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

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

Attachment 2

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

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

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

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

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

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

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

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

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

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

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

1. Examples of evidence for Section 5.1 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.
2. Examples of evidence for Section 5.2 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that

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

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

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Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

~~The~~In developing policies in compliance with Requirement R1, the number of policies and their-
~~specific language are~~
content should be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a -general information security program for the entire organization, or as components of specific programs. ~~The cyber security policy must cover in sufficient detail the nine topical areas required by CIP-003-5, Requirement R1.~~ The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering ~~these~~the required topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-~~57~~, Requirement R1.-

If a Responsible Entity has any high or medium impact BES Cyber Systems, the one or more cyber security policies must cover the nine subject matter areas required by CIP-003-7, Requirement R1, Part 1.1. If a Responsible Entity has identified from CIP-002 any assets containing low impact BES Cyber Systems, the one or more cyber security policies must cover the six subject matter areas required by Requirement R1, Part 1.2.

Responsible Entities that have multiple-impact rated BES Cyber Systems are not required to create separate cyber security policies for high, medium, or low impact BES Cyber Systems. The Responsible Entities have the flexibility to develop policies that cover all three impact ratings.

Implementation of the cyber security policy is not specifically included in CIP-003-~~57~~, Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-~~004003~~ through CIP-011. However, Responsible Entities are

CIP-003-7 Supplemental Material

encouraged not to limit the scope of their cyber security policies to only those requirements ~~from CIP-004 through CIP-011, but rather to put together a holistic cyber security policy appropriate to its organization. The assessment through the Compliance Monitoring and Enforcement Program of policy items that extend beyond the scope of CIP-004 through CIP-011 should not be considered candidates for potential violations. The Responsible Entity should consider the following for each of the required topics in its cyber security policy:~~in NERC cyber security Reliability Standards, but to develop a holistic cyber security policy

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appropriate for its organization. Elements of a policy that extend beyond the scope of NERC's cyber security Reliability Standards will not be considered candidates for potential violations although they will help demonstrate the organization's internal culture of compliance and posture towards cyber security.

For Part 1.1, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for medium and high impact BES Cyber Systems, if any:

1.1.1 Personnel ~~&~~and training (CIP-004)

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- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

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

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN “split-tunneling” or “dual-homed” workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity’s Interactive Remote Access controls

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

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

1.1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

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

- Availability of spare components
- Availability of system backups

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

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

The Standard Drafting Team (SDT) has removed requirements relating to exceptions to a For Part 1.2, the Responsible Entity may consider the following for each of the required topics in its one or more cyber security policies for assets containing low impact BES Cyber Systems, if any:

1.2.1 Cyber security awareness

- Method(s) for delivery of security awareness
- Identification of groups to receive cyber security awareness

1.2.2 Physical security controls

- Acceptable approach(es) for selection of physical security control(s)

1.2.3 Electronic access controls

- Acceptable approach(es) for selection of electronic access control(s)

1.2.4 Cyber Security Incident response

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.2.5 Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

- Acceptable use of Transient Cyber Asset(s) and Removable Media
- Method(s) to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media
- Method(s) to request Transient Cyber Asset and Removable Media

1.2.6 Declaring and responding to CIP Exceptional Circumstances

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- Process(es) to declare a CIP Exceptional Circumstance
- Process(es) to respond to a declared CIP Exceptional Circumstance

Requirements relating to exceptions to a Responsible Entity's security policies ~~since were removed because~~ it is a general management issue that is not within the scope of a reliability requirement. ~~The SDT considers it to be~~ is an internal policy requirement and not a reliability requirement. However, ~~the SDT encourages~~ Responsible Entities are encouraged to continue this practice as a component of ~~its~~ their cyber security ~~policy~~ policies.

In this and all subsequent required approvals in the NERC CIP Reliability Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

~~As with Requirement R1, the number of policies and their specific language would be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization or as components of specific programs. The cyber security policy must cover in sufficient detail the four topical areas required by CIP-003-5, Requirement R2. The Responsible Entity has flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower-level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5, Requirement R2. The intent of the requirement is to outline a set of basic protections that all low impact BES Cyber Systems should receive without requiring a significant administrative and compliance overhead. The SDT intends that demonstration of this requirement can be reasonably accomplished through providing evidence of related processes, procedures, or plans. While the audit staff may choose to review an example low impact BES Cyber System, the SDT believes strongly that the current method (as of this writing) of reviewing a statistical sample of systems is not~~

~~necessary. The SDT also notes that in topic 2.3, the SDT uses the term "electronic access control" in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing.~~

The intent of Requirement R2 is for each Responsible Entity to create, document, and implement one or more cyber security plan(s) that address the security objective for the protection of low impact BES Cyber Systems. The required protections are designed to be part of a program that covers the low impact BES Cyber Systems collectively at an asset level (based on the list of assets containing low impact BES Cyber Systems identified in CIP-002), but not at an individual device or system level.

Requirement R2, Attachment 1

As noted, Attachment 1 contains the sections that must be included in the cyber security plan(s). The intent is to allow entities that have a combination of high, medium, and low impact BES Cyber Systems the flexibility to choose, if desired, to cover their low impact BES Cyber Systems (or any subset) under their programs used for the high or medium impact BES Cyber Systems rather than maintain two separate programs. The purpose of the cyber security plan(s) in Requirement R2 is for Responsible Entities to use the cyber security plan(s) as a means of documenting their approaches to meeting the subject matter areas. The cyber security plan(s) can be used to reference other policies and procedures that demonstrate “how” the Responsible Entity is meeting each of the subject matter areas, or Responsible Entities can develop comprehensive cyber security plan(s) that contain all of the detailed implementation content solely within the cyber security plan itself. To meet the obligation for the cyber security plan, the expectation is that the cyber security plan contains or references sufficient details to address the implementation of each of the required subject matters areas.

Guidance for each of the subject matter areas of Attachment 1 is provided below.

Requirement R2, Attachment 1, Section 1 – Cyber Security Awareness

The intent of the cyber security awareness program is for entities to reinforce good cyber security practices with their personnel at least once every 15 calendar months. The entity has the discretion to determine the topics to be addressed and the manner in which it will communicate these topics. As evidence of compliance, the Responsible Entity should be able to produce the awareness material that was delivered according to the delivery method(s) (e.g., posters, emails, or topics at staff meetings, etc.). The standard drafting team does not intend for Responsible Entities to be required to maintain lists of recipients and track the reception of the awareness material by personnel.

Although the focus of the awareness is cyber security, it does not mean that only technology-related topics can be included in the program. Appropriate physical security topics (e.g., tailgating awareness and protection of badges for physical security, or “If you see something, say something” campaigns, etc.) are valid for cyber security awareness. The intent is to cover topics concerning any aspect of the protection of BES Cyber Systems.

Requirement R2, Attachment 1, Section 2 – Physical Security Controls

The Responsible Entity must document and implement methods to control physical access to (1) the asset or the locations of low impact BES Cyber Systems within the asset, and (2) Cyber Assets that implement the electronic access control(s) specified by the Responsible Entity in Attachment 1, Section 3.1, if any. If these Cyber Assets implementing the electronic access controls are located within the same asset as the low impact BES Cyber Asset(s) and inherit the same physical access controls and the same need as outlined in Section 2, this may be noted by the Responsible Entity in either its policies or cyber security plan(s) to avoid duplicate documentation of the same controls.

The Responsible Entity has the flexibility to select the methods used to meet the objective of controlling physical access to (1) the asset(s) containing low impact BES Cyber System(s) or the low impact BES Cyber Systems themselves and (2) the electronic access control Cyber Assets specified by the Responsible Entity, if any. The Responsible Entity may use one or a

combination of physical access controls, monitoring controls, or other operational, procedural, or technical physical security controls. Entities may use perimeter controls (e.g., fences with locked gates, guards, or site access policies, etc.) or more granular areas of physical access control in areas where low impact BES Cyber Systems are located, such as control rooms or control houses.

The security objective is to control the physical access based on need as determined by the Responsible Entity. The need for physical access can be documented at the policy level. The standard drafting team did not intend to obligate an entity to specify a need for each physical access or authorization of an individual for physical access.

Monitoring as a physical security control can be used as a complement or an alternative to physical access control. Examples of monitoring controls include, but are not limited to: (1) alarm systems to detect motion or entry into a controlled area, or (2) human observation of a controlled area. Monitoring does not necessarily require logging and maintaining logs but could include monitoring that physical access has occurred or been attempted (e.g., door alarm, or human observation, etc.). The standard drafting team's intent is that the monitoring does not need to be per low impact BES Cyber System but should be at the appropriate level to meet the security objective of controlling physical access.

User authorization programs and lists of authorized users for physical access are not required although they are an option to meet the security objective.

Requirement R2, Attachment 1, Section 3 – Electronic Access Controls

Section 3 requires the establishment of electronic access controls for assets containing low impact BES Cyber Systems when there is routable protocol communication or Dial-up Connectivity between Cyber Asset(s) outside of the asset containing the low impact BES Cyber System(s) and the low impact BES Cyber System(s) within such asset. The establishment of electronic access controls is intended to reduce the risks associated with uncontrolled communication using routable protocols or Dial-up Connectivity.

When implementing Attachment 1, Section 3.1, Responsible Entities should note that electronic access controls to permit only necessary inbound and outbound electronic access are required for communications when those communications meet all three of the criteria identified in Attachment 1, Section 3.1. The Responsible Entity should evaluate the communications and when all three criteria are met, the Responsible Entity must document and implement electronic access control(s).

When identifying electronic access controls, Responsible Entities are provided flexibility in the selection of the electronic access controls that meet their operational needs while meeting the security objective of allowing only necessary inbound and outbound electronic access to low impact BES Cyber Systems that use routable protocols between a low impact BES Cyber System(s) and Cyber Asset(s) outside the asset.

In essence, the intent is for Responsible Entities to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset or Dial-up Connectivity to the low impact BES Cyber System(s). Where such

communication is present, Responsible Entities should document and implement electronic access control(s). Where routable protocol communication for time-sensitive protection or control functions between intelligent electronic devices that meets the exclusion language is present, Responsible Entities should document that communication, but are not required to establish any specific electronic access controls.

The inputs to this requirement are the assets identified in CIP-002 as containing low impact BES Cyber System(s); therefore, the determination of routable protocol communications or Dial-up Connectivity is an attribute of the asset. However, it is not intended for communication that provides no access to or from the low impact BES Cyber System(s), but happens to be located at the asset with the low impact BES Cyber System(s), to be evaluated for electronic access controls.

Electronic Access Control Exclusion

In order to avoid future technology issues, the obligations for electronic access controls exclude communications between intelligent electronic devices that use routable communication protocols for time-sensitive protection or control functions, such as IEC TR-61850-90-5 R-GOOSE messaging. Time-sensitive in this context generally means functions that would be negatively impacted by the latency introduced in the communications by the required electronic access controls. This time-sensitivity exclusion does not apply to SCADA communications which typically operate on scan rates of 2 seconds or greater. While technically time-sensitive, SCADA communications over routable protocols can withstand the delay introduced by electronic access controls. Examples of excluded time-sensitive communications are those communications which may necessitate the tripping of a breaker within a few cycles. A Responsible Entity using this technology is not expected to implement the electronic access controls noted herein. This exception was included so as not to inhibit the functionality of the time-sensitive characteristics related to this technology and not to preclude the use of such time-sensitive reliability enhancing functions if they use a routable protocol in the future.

Considerations for Determining Routable Protocol Communications

To determine whether electronic access controls need to be implemented, the Responsible Entity has to determine whether there is communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset.

When determining whether a routable protocol is entering or leaving the asset containing the low impact BES Cyber System(s), Responsible Entities have flexibility in identifying an approach. One approach is for Responsible Entities to identify an “electronic boundary” associated with the asset containing low impact BES Cyber System(s). This is not an Electronic Security Perimeter *per se*, but a demarcation that demonstrates the routable protocol communication entering or leaving the asset between a low impact BES Cyber System and Cyber Asset(s) outside the asset to then have electronic access controls implemented. This electronic boundary may vary by asset type (Control Center, substation, generation resource) and the specific configuration of the asset. If this approach is used, the intent is for the Responsible Entity to define the electronic boundary such that the low impact BES Cyber System(s) located

at the asset are contained within the “electronic boundary.” This is strictly for determining which routable protocol communications and networks are internal or inside or local to the asset and which are external to or outside the asset.

Alternatively, the Responsible Entity may find the concepts of what is inside and outside to be intuitively obvious for a Cyber Asset(s) outside the asset containing low impact BES Cyber System(s) communicating to a low impact BES Cyber System(s) inside the asset. This may be the case when a low impact BES Cyber System(s) is communicating with a Cyber Asset many miles away and a clear and unambiguous demarcation exists. In this case, a Responsible Entity may decide not to identify an “electronic boundary,” but rather to simply leverage the unambiguous asset demarcation to ensure that the electronic access controls are placed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset.

Determining Electronic Access Controls

Once a Responsible Entity has determined that there is routable communication between a low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s), the intent is for the Responsible Entity to document and implement its chosen electronic access control(s). The control(s) are intended to allow only “necessary” inbound and outbound electronic access as determined by the Responsible Entity. However the Responsible Entity chooses to document the inbound and outbound access permissions and the need, the intent is that the Responsible Entity is able to explain the reasons for the electronic access permitted. The reasoning for “necessary” inbound and outbound electronic access controls may be documented within the Responsible Entity’s cyber security plan(s), within a comment on an access control list, a database, spreadsheet or other policies or procedures associated with the electronic access controls.

Concept Diagrams

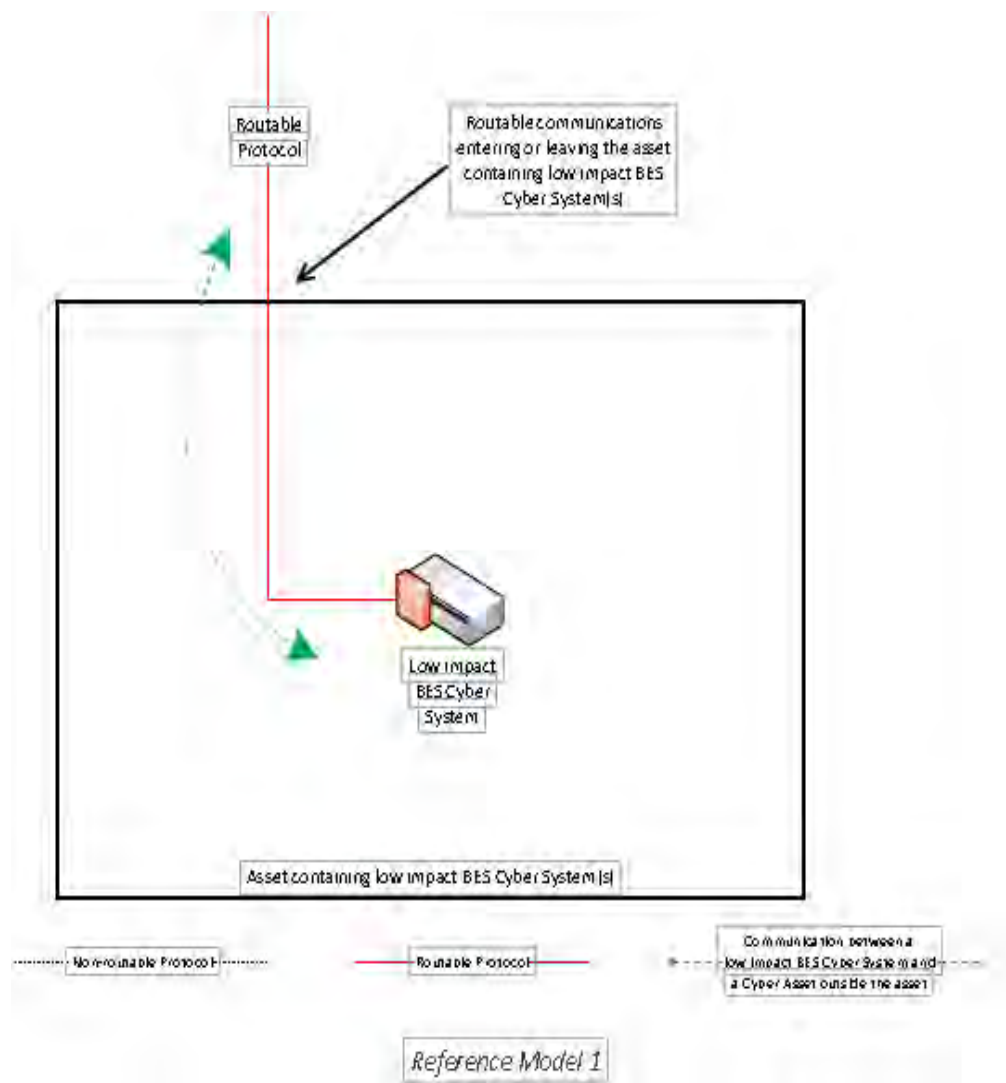
The diagrams on the following pages are provided as examples to illustrate various electronic access controls at a conceptual level. Regardless of the concepts or configurations chosen by the Responsible Entity, the intent is to achieve the security objective of permitting only necessary inbound and outbound electronic access for communication between low impact BES Cyber Systems and Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s) using a routable protocol when entering or leaving the asset.

NOTE:

- This is not an exhaustive list of applicable concepts.
- The same legend is used in each diagram; however, the diagram may not contain all of the articles represented in the legend.

CIP-003-7 Supplemental Material**Reference Model 1 – Host-based Inbound & Outbound Access Permissions**

The Responsible Entity may choose to utilize a host-based firewall technology on the low impact BES Cyber System(s) itself that manages the inbound and outbound electronic access permissions so that only necessary inbound and outbound electronic access is allowed between the low impact BES Cyber System(s) and the Cyber Asset(s) outside the asset containing the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).

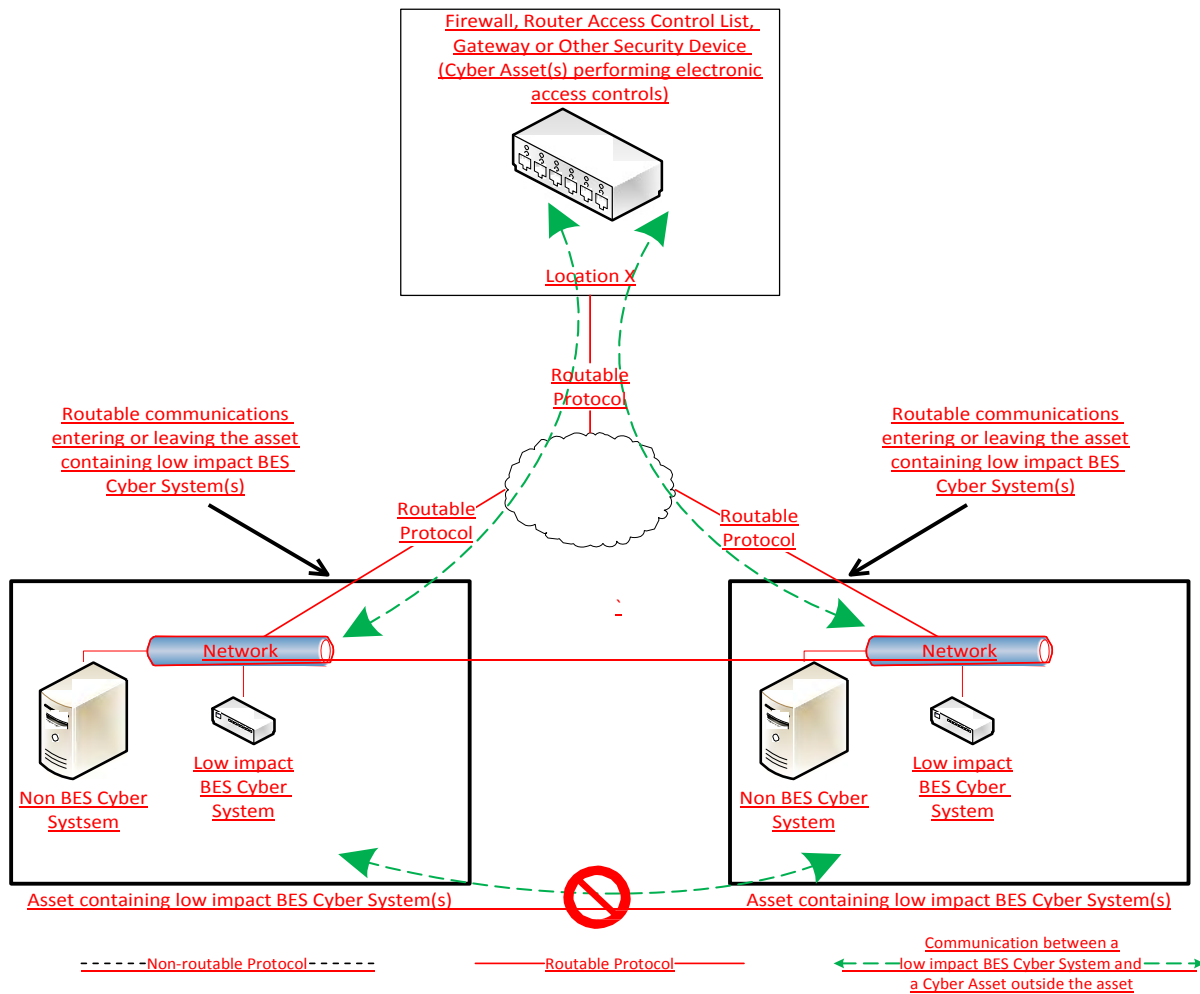


The Responsible Entity may choose to use a security device that permits only necessary inbound and outbound electronic access to the low impact BES Cyber System(s) within the asset containing the low impact BES Cyber System(s). In this example, two low impact BES Cyber Systems are accessed using the routable protocol that is entering or leaving the asset containing the low impact BES Cyber System(s). The IP/Serial converter is continuing the same communications session from the Cyber Asset(s) that are outside the asset to the low impact BES Cyber System(s). The security device provides the electronic access controls to permit only necessary inbound and outbound routable protocol access to the low impact BES Cyber System(s). When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 3 – Centralized Network-based Inbound & Outbound Access Permissions

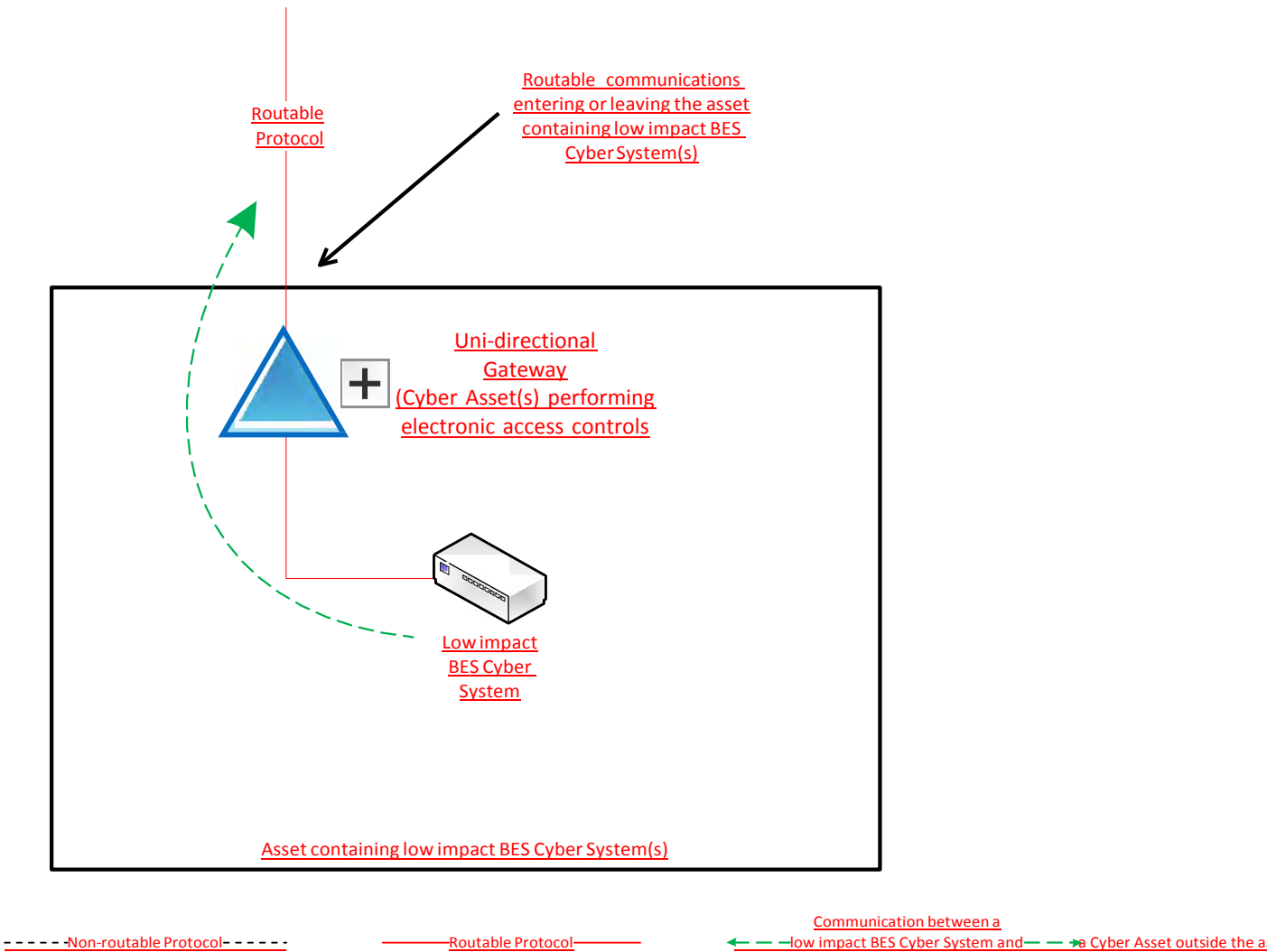
The Responsible Entity may choose to utilize a security device at a centralized location that may or may not be at another asset containing low impact BES Cyber System(s). The electronic access control(s) do not necessarily have to reside inside the asset containing the low impact BES Cyber System(s). A security device is in place at “Location X” to act as the electronic access control and permit only necessary inbound and outbound routable protocol access between the low impact BES Cyber System(s) and the Cyber Asset(s) outside each asset containing low impact BES Cyber System(s). Care should be taken that electronic access to or between each asset is through the Cyber Asset(s) determined by the Responsible Entity to be performing electronic access controls at the centralized location. When permitting the inbound and outbound electronic access permissions using access control lists, the Responsible Entity could restrict communication(s) using source and destination addresses or ranges of addresses. Responsible Entities could also restrict communication(s) using ports or services based on the capability of the electronic access control, the low impact BES Cyber System(s), or the application(s).



Reference Model 3

Reference Model 4 – Uni-directional Gateway

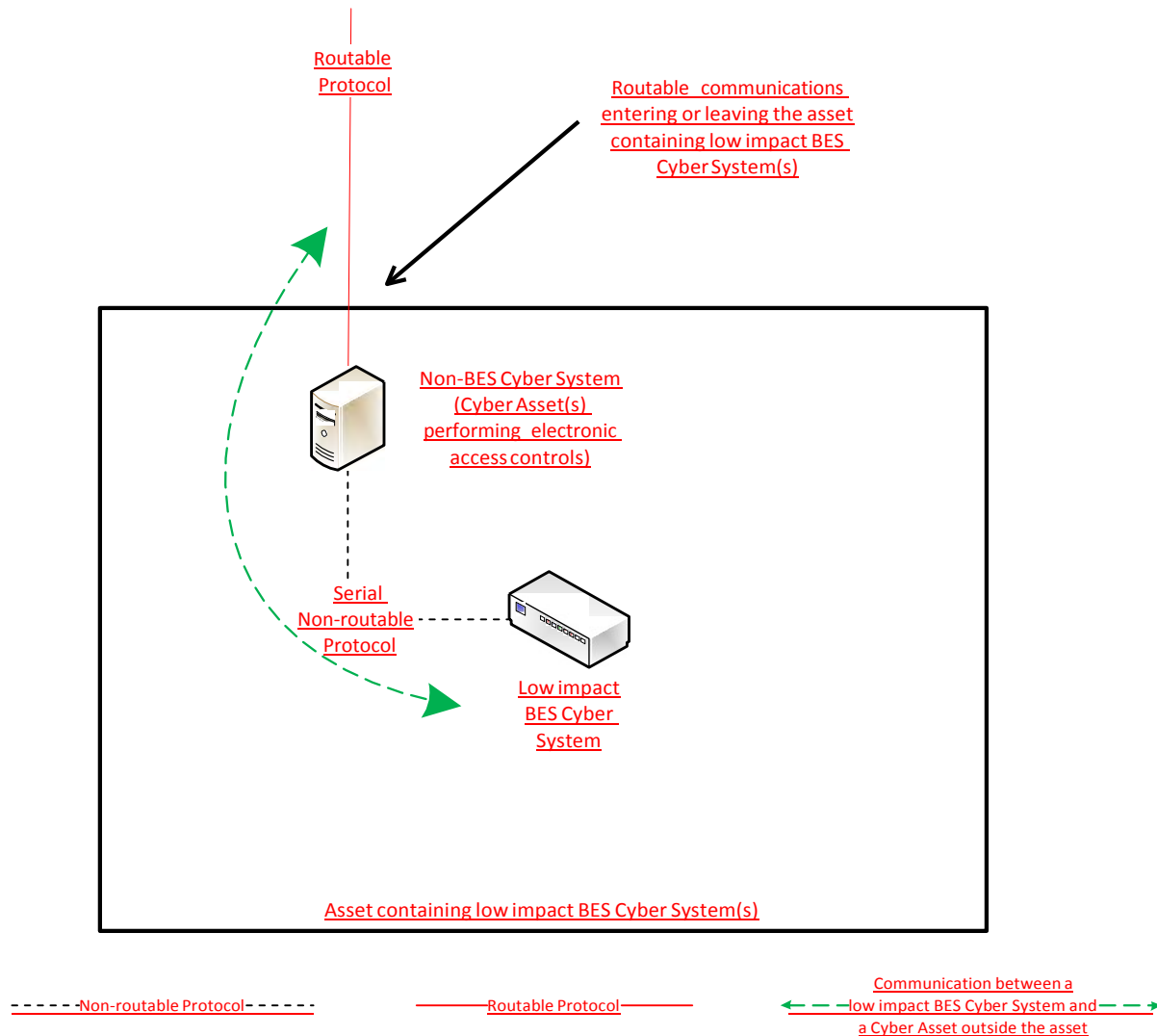
The Responsible Entity may choose to utilize a uni-directional gateway as the electronic access control. The low impact BES Cyber System(s) is not accessible (data cannot flow into the low impact BES Cyber System) using the routable protocol entering the asset due to the implementation of a “one-way” (uni-directional) path for data to flow. The uni-directional gateway is configured to permit only the necessary outbound communications using the routable protocol communication leaving the asset.



Reference Model 4

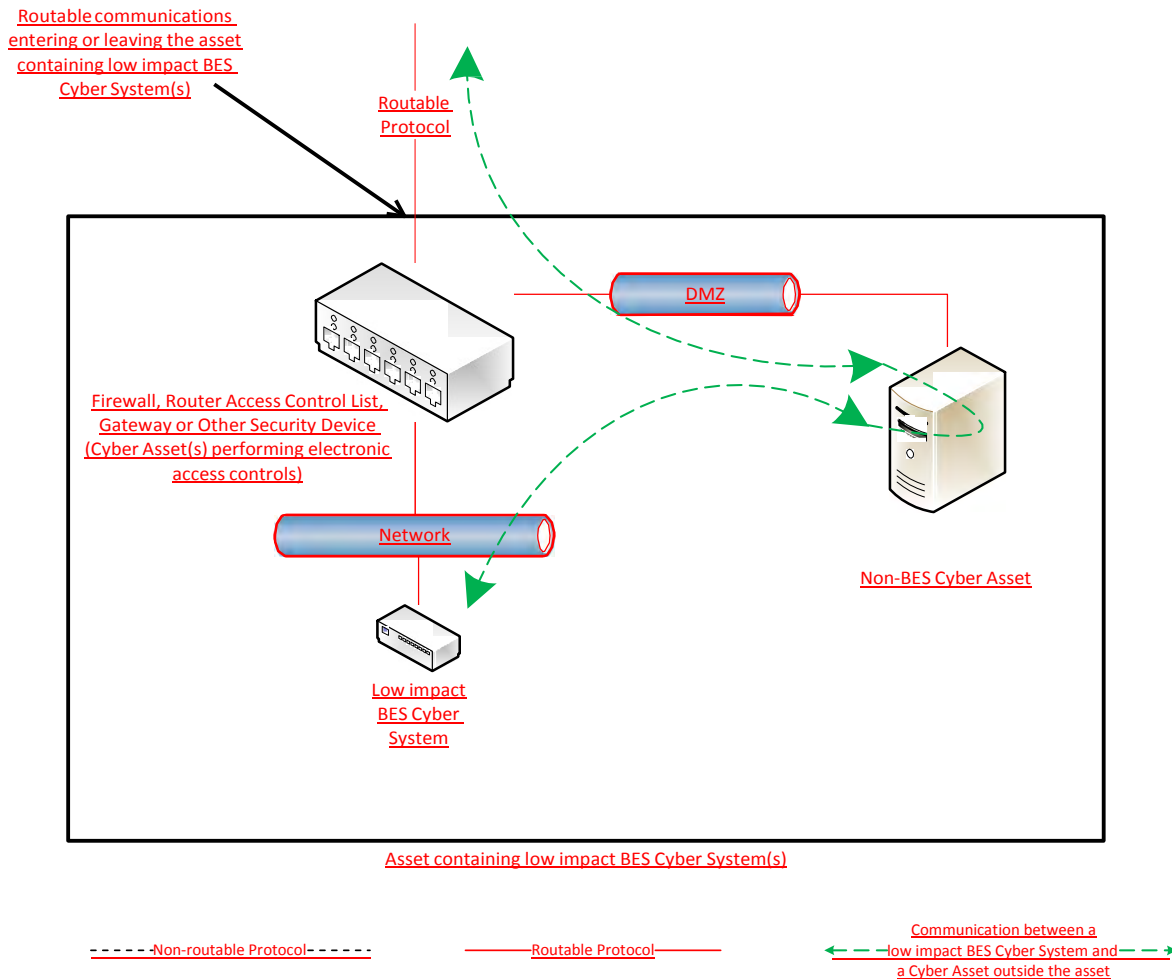
Reference Model 5 – User Authentication

This reference model demonstrates that Responsible Entities have flexibility in choosing electronic access controls so long as the security objective of the requirement is met. The Responsible Entity may choose to utilize a non-BES Cyber Asset located at the asset containing the low impact BES Cyber System that requires authentication for communication from the Cyber Asset(s) outside the asset. This non-BES Cyber System performing the authentication permits only authenticated communication to connect to the low impact BES Cyber System(s), meeting the first half of the security objective to permit only necessary inbound electronic access. Additionally, the non-BES Cyber System performing authentication is configured such that it permits only necessary outbound communication meeting the second half of the security objective. Often, the outbound communications would be controlled in this network architecture by permitting no communication to be initiated from the low impact BES Cyber System. This configuration may be beneficial when the only communication to a device is for user-initiated interactive access.

**Reference Model 5**

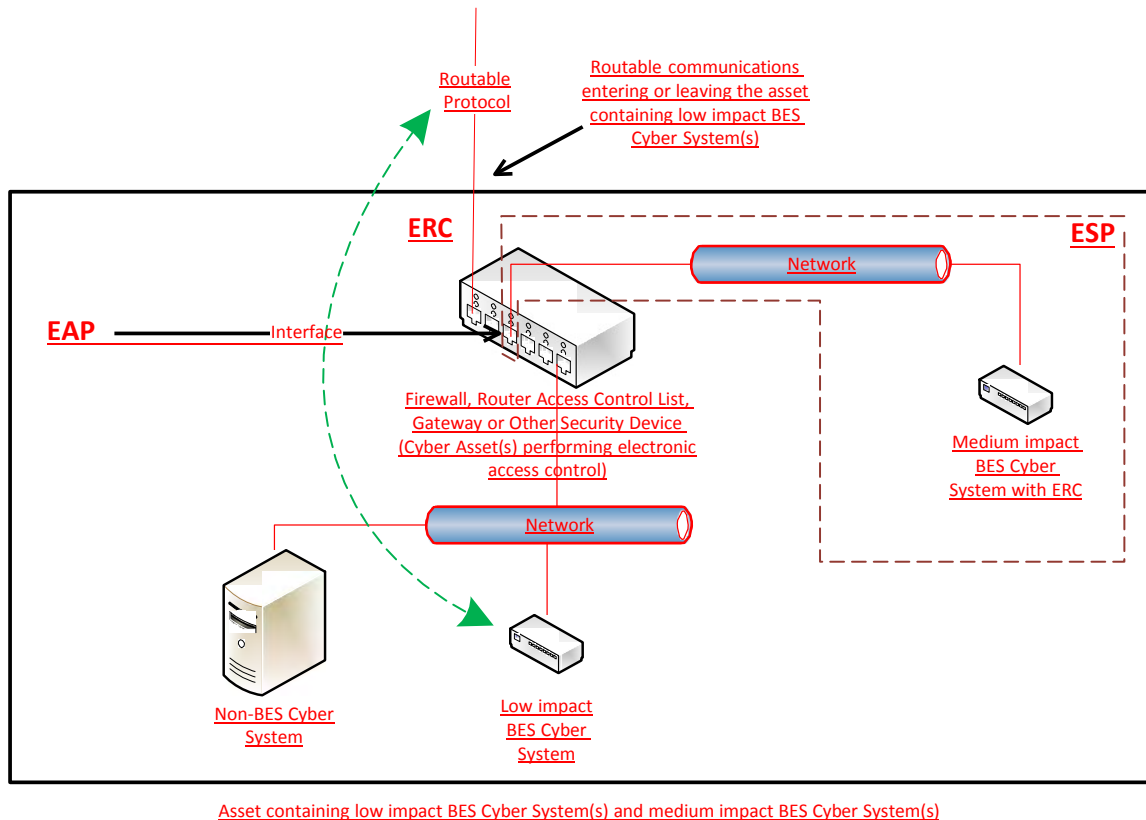
Reference Model 6 – Indirect Access

In implementing its electronic access controls, the Responsible Entity may identify that it has indirect access between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System through a non-BES Cyber Asset located within the asset. This indirect access meets the criteria of having communication between the low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System. In this reference model, it is intended that the Responsible Entity implement electronic access controls that permit only necessary inbound and outbound electronic access to the low impact BES Cyber System. Consistent with the other reference models provided, the electronic access in this reference model is controlled using the security device that is restricting the communication that is entering or leaving the asset.

**Reference Model 6**

Reference Model 7 – Electronic Access Controls at assets containing low impact BES Cyber Systems and ERC

In this reference model, there is both a routable protocol entering and leaving the asset containing the low impact BES Cyber System(s) that is used by Cyber Asset(s) outside the asset and External Routable Connectivity because there is at least one medium impact BES Cyber System and one low impact BES Cyber System within the asset using the routable protocol communications. The Responsible Entity may choose to leverage an interface on the medium impact Electronic Access Control or Monitoring Systems (EACMS) to provide electronic access controls for purposes of CIP-003. The EACMS is therefore performing multiple functions – as a medium impact EACMS and as implementing electronic access controls for an asset containing low impact BES Cyber Systems.

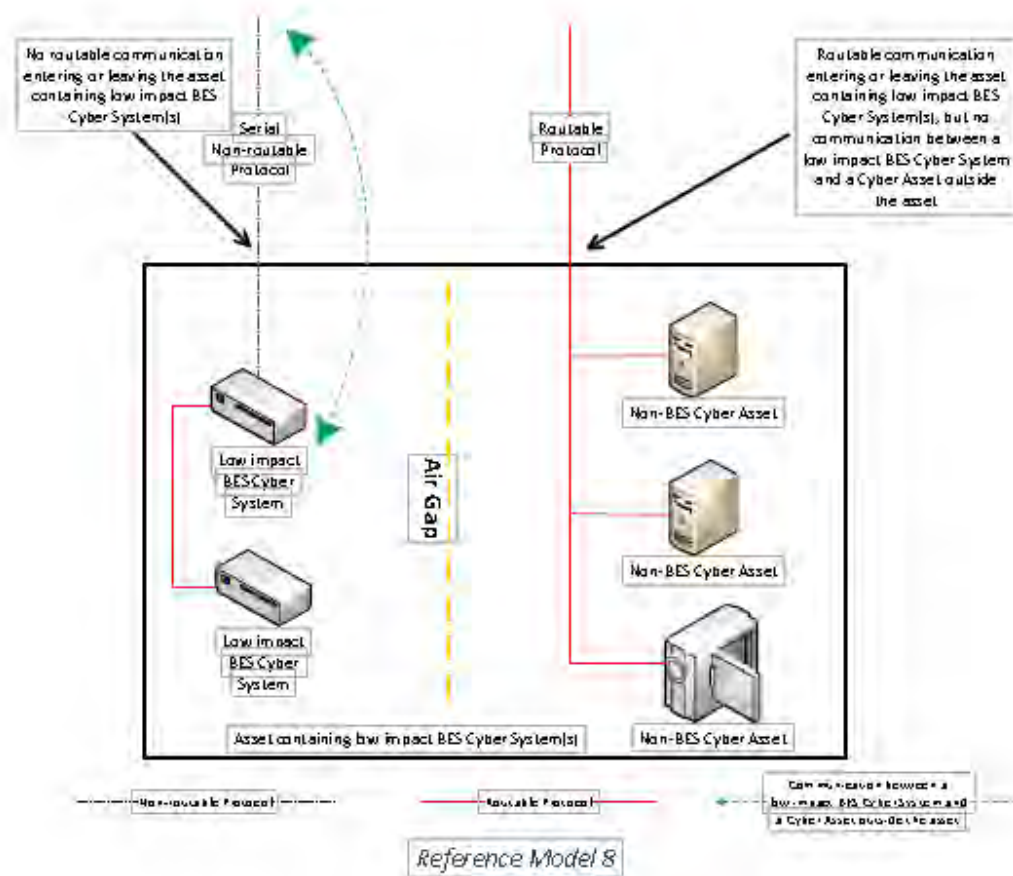


Reference Model 7

Reference Model 8 – Physical Isolation and Serial Non-routable Communications – No Electronic Access Controls Required

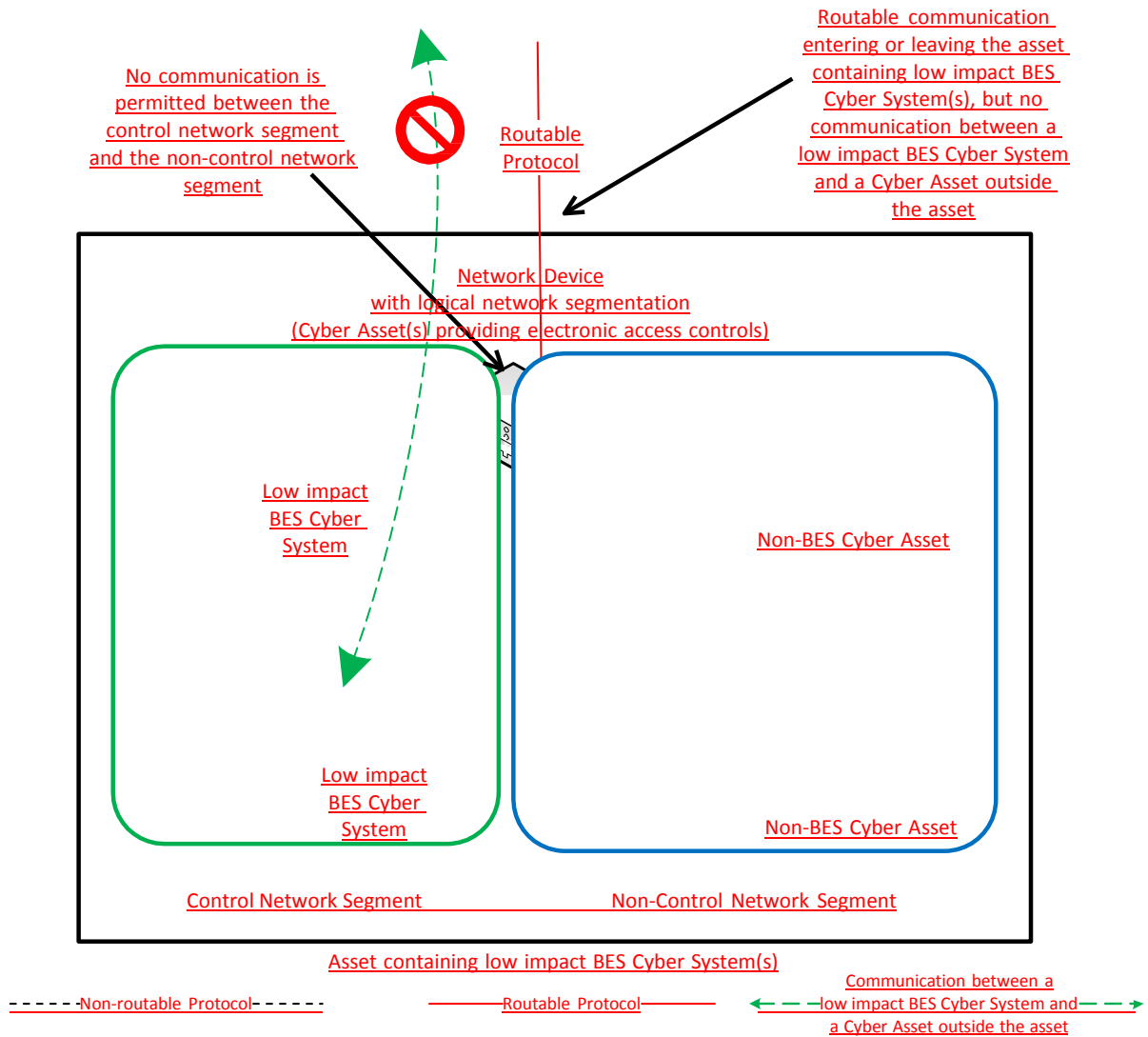
In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model demonstrates three concepts:

- 1) The physical isolation of the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing the low impact BES Cyber System(s), commonly referred to as an 'air gap', mitigates the need to implement the required electronic access controls;
- 2) The communication to the low impact BES Cyber System from a Cyber Asset outside the asset containing the low impact BES Cyber System(s) using only a serial non-routable protocol where such communication is entering or leaving the asset mitigates the need to implement the required electronic access controls.
- 3) The routable protocol communication between the low impact BES Cyber System(s) and other Cyber Asset(s), such as the second low impact BES Cyber System depicted, may exist without needing to implement the required electronic access controls so long as the routable protocol communications never leaves the asset containing the low impact BES Cyber System(s).



CIP-003-7 Supplemental Material**CIP-003-7 Supplemental Material****Reference Model 9 – Logical Isolation - No Electronic Access Controls Required**

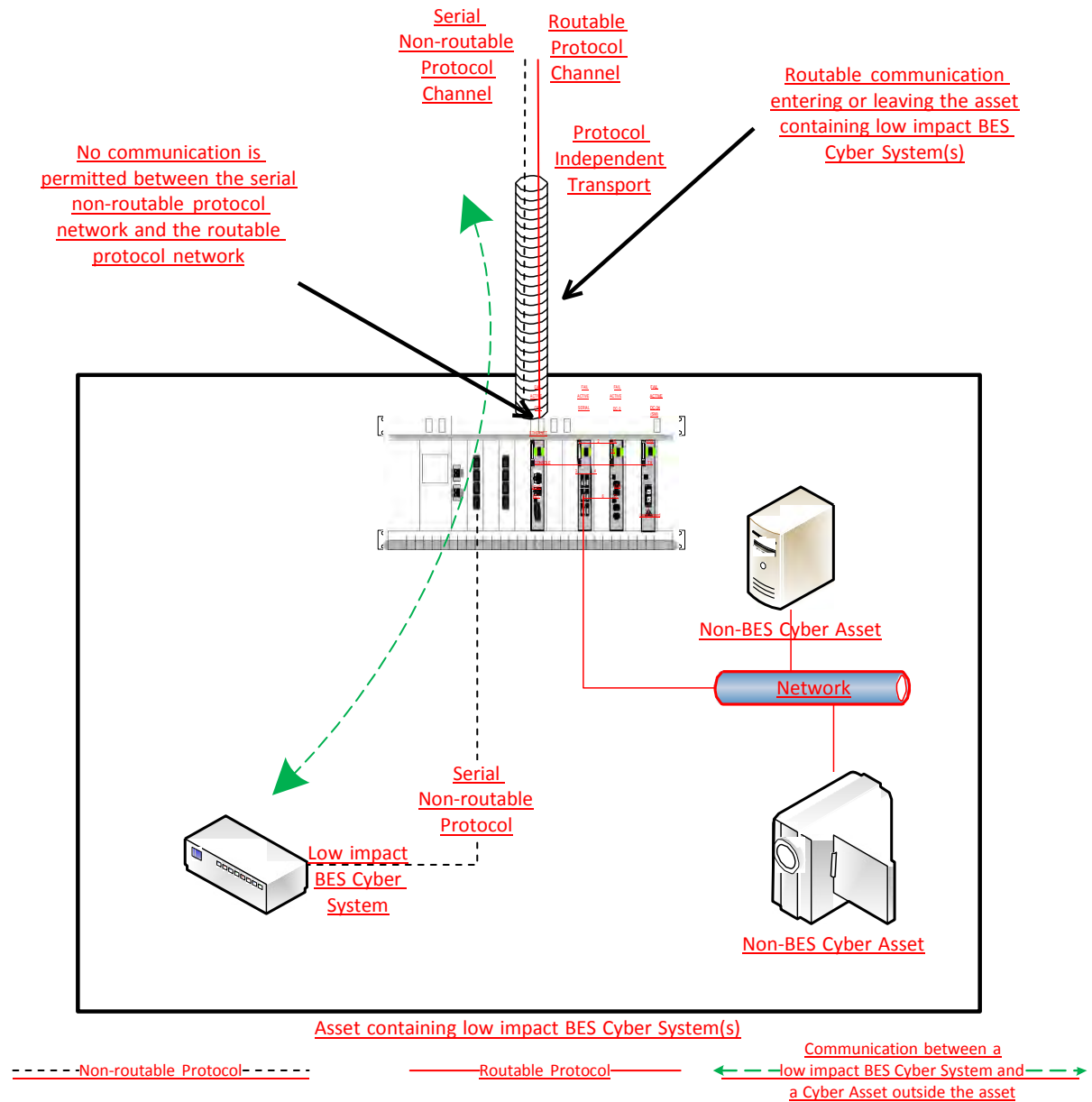
In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. The Responsible Entity has logically isolated the low impact BES Cyber System(s) from the routable protocol communication entering or leaving the asset containing low impact BES Cyber System(s). The logical network segmentation in this reference model permits no communication between a low impact BES Cyber System and a Cyber Asset outside the asset. Additionally, no indirect access exists because those non-BES Cyber Assets that are able to communicate outside the asset are strictly prohibited from communicating to the low impact BES Cyber System(s). The low impact BES Cyber System(s) is on an isolated network segment with logical controls preventing routable protocol communication into or out of the network containing the low impact BES Cyber System(s) and these communications never leave the asset using a routable protocol.



Reference Model 9

Reference Model 10 - Serial Non-routable Communications Traversing an Isolated Channel on a Non-routable Transport Network – No Electronic Access Controls Required

In this reference model, the criteria from Attachment 1, Section 3.1 requiring the implementation of electronic access controls are not met. This reference model depicts communication between a low impact BES Cyber System and a Cyber Asset outside the asset containing the low impact BES Cyber System over a serial non-routable protocol which is transported across a wide-area network using a protocol independent transport that may carry routable and non-routable communication such as a Time-Division Multiplexing (TDM) network, a Synchronous Optical Network (SONET), or a Multiprotocol Label Switching (MPLS) network. While there is routable protocol communication entering or leaving the asset containing low impact BES Cyber Systems(s) and there is communication between a low impact BES Cyber System and a Cyber Asset outside the asset, the communication between the low impact BES Cyber System and the Cyber Asset outside the asset is not using the routable protocol communication. This model is related to Reference Model 9 in that it relies on logical isolation to prohibit the communication between a low impact BES Cyber System and a Cyber Asset outside the asset from using a routable protocol.



Reference Model 10

Dial-up Connectivity

Dial-up Connectivity to a low impact BES Cyber System is set to dial out only (no auto-answer) to a preprogrammed number to deliver data. Incoming Dial-up Connectivity is to a dialback modem, a modem that must be remotely controlled by the control center or control room, has some form of access control, or the low impact BES Cyber System has access control.

Insufficient Access Controls

Some examples of situations that would lack sufficient access controls to meet the intent of this requirement include:

- An asset has Dial-up Connectivity and a low impact BES Cyber System is reachable via an auto-answer modem that connects any caller to the Cyber Asset that has a default password. There is no practical access control in this instance.
- A low impact BES Cyber System has a wireless card on a public carrier that allows the BES Cyber System to be reachable via a public IP address. In essence, low impact BES Cyber Systems should not be accessible from the Internet and search engines such as Shodan.
- Dual-homing or multiple-network interface cards without disabling IP forwarding in the non-BES Cyber Asset within the DMZ to provide separation between the low impact BES Cyber System(s) and the external network would not meet the intent of “controlling” inbound and outbound electronic access assuming there was no other host-based firewall or other security devices on the non-BES Cyber Asset.

Requirement R2, Attachment 1, Section 4 – Cyber Security Incident Response

The entity should have one or more documented Cyber Security Incident response plan(s) that include each of the topics listed in Section 4. If, in the normal course of business, suspicious activities are noted at an asset containing low impact BES Cyber System(s), the intent is for the entity to implement a Cyber Security Incident response plan that will guide the entity in responding to the incident and reporting the incident if it rises to the level of a Reportable Cyber Security Incident.

Entities are provided the flexibility to develop their Attachment 1, Section 4 Cyber Security Incident response plan(s) by asset or group of assets. The plans do not need to be on a per asset site or per low impact BES Cyber System basis. Entities can choose to use a single enterprise-wide plan to fulfill the obligations for low impact BES Cyber Systems.

The plan(s) must be tested once every 36 months. This is not an exercise per low impact BES Cyber Asset or per type of BES Cyber Asset but rather is an exercise of each incident response plan the entity created to meet this requirement. An actual Reportable Cyber Security Incident counts as an exercise as do other forms of tabletop exercises or drills. NERC-led exercises such as GridEx participation would also count as an exercise provided the entity’s response plan is followed. The intent of the requirement is for entities to keep the Cyber Security Incident response plan(s) current, which includes updating the plan(s), if needed, within 180 days following a test or an actual incident.

For low impact BES Cyber Systems, the only portion of the definition of Cyber Security Incident that would apply is, “A malicious act or suspicious event that disrupts, or was an attempt to

disrupt, the operation of a BES Cyber System.” The other portion of that definition is not to be used to require ESPs and PSPs for low impact BES Cyber Systems.

Requirement R2, Attachment 1, Section 5 – Transient Cyber Assets and Removable Media Malicious Code Risk Mitigation

Most BES Cyber Assets and BES Cyber Systems are isolated from external public or untrusted networks, and therefore Transient Cyber Assets and Removable Media are needed to transport files to and from secure areas to maintain, monitor, or troubleshoot critical systems. Transient Cyber Assets and Removable Media are a potential means for cyber-attack. To protect the BES Cyber Assets and BES Cyber Systems, CIP-003 Requirement R2, Attachment 1, Section 5 requires Responsible Entities to document and implement a plan for how they will mitigate the risk of malicious code introduction to low impact BES Cyber Systems from Transient Cyber Assets and Removable Media. The approach of defining a plan allows the Responsible Entity to document processes that are supportable within its organization and in alignment with its change management processes.

Transient Cyber Assets can be one of many types of devices from a specially-designed device for maintaining equipment in support of the BES to a platform such as a laptop, desktop, or tablet that may interface with or run applications that support BES Cyber Systems and is capable of transmitting executable code to the BES Cyber Asset(s) or BES Cyber System(s). Note: Cyber Assets connected to a BES Cyber System for less than 30 days due to an unplanned removal, such as premature failure, are not intended to be identified as Transient Cyber Assets. Removable Media subject to this requirement include, among others, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

Examples of these temporarily connected devices include, but are not limited to:

- Diagnostic test equipment;
- Equipment used for BES Cyber System maintenance; or
- Equipment used for BES Cyber System configuration.

To meet the objective of mitigating risks associated with the introduction of malicious code at low impact BES Cyber Systems, Section 5 specifies the capabilities and possible security methods available to Responsible Entities based upon asset type and ownership.

With the list of options provided in Attachment 1, the entity has the discretion to use the option(s) that is most appropriate. This includes documenting its approach for how and when the entity reviews the Transient Cyber Asset under its control or under the control of parties other than the Responsible Entity. The entity should avoid implementing a security function that jeopardizes reliability by taking actions that would negatively impact the performance or support of the Transient Cyber Asset or BES Cyber Asset.

Malicious Code Risk Mitigation

The terms “mitigate”, “mitigating”, and “mitigation” are used in Section 5 in Attachment 1 to address the risks posed by malicious code when connecting Transient Cyber Assets and Removable Media to BES Cyber Systems. Mitigation is intended to mean that entities reduce security risks presented by connecting the Transient Cyber Asset or Removable Media. When determining the method(s) to mitigate the introduction of malicious code, it is not intended for entities to perform and document a formal risk assessment associated with the introduction of malicious code.

Per Transient Cyber Asset Capability

As with other CIP standards, the requirements are intended for an entity to use the method(s) that the system is capable of performing. The use of “per Transient Cyber Asset capability” is to eliminate the need for a Technical Feasibility Exception when it is understood that the device cannot use a method(s). For example, for malicious code, many types of appliances are not capable of implementing antivirus software; therefore, because it is not a capability of those types of devices, implementation of the antivirus software would not be required for those devices.

Requirement R2, Attachment 1, Section 5.1 - Transient Cyber Asset(s) Managed by the Responsible Entity

For Transient Cyber Assets and Removable Media that are connected to both low impact and medium/high impact BES Cyber Systems, entities must be aware of the differing levels of requirements and manage these assets under the program that matches the highest impact level to which they will connect.

Section 5.1: Entities are to document and implement their plan(s) to mitigate malicious code through the use of one or more of the protective measures listed, based on the capability of the Transient Cyber Asset.

The Responsible Entity has the flexibility to apply the selected method(s) to meet the objective of mitigating the introductions of malicious code either in an on-going or in an on-demand manner. An example of managing a device in an on-going manner is having the antivirus solution for the device managed as part of an end-point security solution with current signature or pattern updates, regularly scheduled systems scans, etc. In contrast, for devices that are used infrequently and the signatures or patterns are not kept current, the entity may manage those devices in an on-demand manner by requiring an update to the signatures or patterns and a scan of the device before the device is connected to ensure that it is free of malicious code.

Selecting management in an on-going or on-demand manner is not intended to imply that the control has to be verified at every single connection. For example, if the device is managed in an on-demand manner, but will be used to perform maintenance on several BES Cyber Asset(s), the Responsible Entity may choose to document that the Transient Cyber Asset has been updated before being connected as a Transient Cyber Asset for the first use of that maintenance work. The intent is not to require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

The following is additional discussion of the methods to mitigate the introduction of malicious code.

- Antivirus software, including manual or managed updates of signatures or patterns, provides flexibility to manage Transient Cyber Asset(s) by deploying antivirus or endpoint security tools that maintain a scheduled update of the signatures or patterns. Also, for devices that do not regularly connect to receive scheduled updates, entities may choose to update the signatures or patterns and scan the Transient Cyber Asset prior to connection to ensure no malicious software is present.
- Application whitelisting is a method of authorizing only the applications and processes that are necessary on the Transient Cyber Asset. This reduces the risk that malicious software could execute on the Transient Cyber Asset and impact the BES Cyber Asset or BES Cyber System.
- When using methods other than those listed, entities need to document how the other method(s) meet the objective of mitigating the risk of the introduction of malicious code.

If malicious code is discovered on the Transient Cyber Asset, it must be mitigated prior to connection to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. An entity may choose to not connect the Transient Cyber Asset to a BES Cyber System to prevent the malicious code from being introduced into the BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident.

Requirement R2, Attachment 1, Section 5.2 - Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity

Section 5 also recognizes the lack of direct control over Transient Cyber Assets that are managed by parties other than the Responsible Entity. This lack of control, however, does not obviate the Responsible Entity's responsibility to ensure that methods have been deployed to mitigate the introduction of malicious code to low impact BES Cyber System(s) from Transient Cyber Assets it does not manage. Section 5 requires entities to review the other party's security practices with respect to Transient Cyber Assets to help meet the objective of the requirement. The use of "prior to connecting the Transient Cyber Assets" is intended to ensure that the Responsible Entity conducts the review before the first connection of the Transient Cyber Asset to help meet the objective to mitigate the introduction of malicious code. The SDT does not intend for the Responsible Entity to conduct a review for every single connection of that Transient Cyber Asset once the Responsible Entity has established the Transient Cyber Asset is meeting the security objective. The intent is to not require a log documenting each connection of a Transient Cyber Asset to a BES Cyber Asset.

To facilitate these controls, Responsible Entities may execute agreements with other parties to provide support services to BES Cyber Systems and BES Cyber Assets that may involve the use of Transient Cyber Assets. Entities may consider using the Department of Energy Cybersecurity Procurement Language for Energy Delivery dated April 2014.¹ Procurement language may unify

¹ <http://www.energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014>

the other party and entity actions supporting the BES Cyber Systems and BES Cyber Assets. CIP program attributes may be considered including roles and responsibilities, access controls, monitoring, logging, vulnerability, and patch management along with incident response and back up recovery may be part of the other party's support. Entities may consider the "General Cybersecurity Procurement Language" and "The Supplier's Life Cycle Security Program" when drafting Master Service Agreements, Contracts, and the CIP program processes and controls.

Section 5.2: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more of the protective measures listed.

- Review the use of antivirus software and signature or pattern levels to ensure that the level is adequate to the Responsible Entity to mitigate the risk of malicious software being introduced to an applicable system.
- Review the antivirus or endpoint security processes of the other party to ensure that their processes are adequate to the Responsible Entity to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of application whitelisting used by the other party to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of live operating systems or software executable only from read-only media to ensure that the media is free from malicious software itself. Entities should review the processes to build the read-only media as well as the media itself.
- Review system hardening practices used by the other party to ensure that unnecessary ports, services, applications, etc. have been disabled or removed. This method intends to reduce the attack surface on the Transient Cyber Asset and reduce the avenues by which malicious software could be introduced.

Requirement R2, Attachment 1, Section 5.3 - Removable Media

Entities have a high level of control for Removable Media that are going to be connected to their BES Cyber Assets.

Section 5.3: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more method(s) to detect malicious code on the Removable Media before it is connected to a BES Cyber Asset. When using the method(s) to detect malicious code, it is expected to occur from a system that is not part of the BES Cyber System to reduce the risk of propagating malicious code into the BES Cyber System network or onto one of the BES Cyber Assets. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident. Frequency and timing of the methods used to detect malicious code were intentionally excluded from the requirement because there are multiple timing scenarios that

can be incorporated into a plan to mitigate the risk of malicious code. The SDT does not intend to obligate a Responsible Entity to conduct a review for every single connection of Removable Media, but rather to implement its plan(s) in a manner that protects all BES Cyber Systems where Removable Media may be used. The intent is to not require a log documenting each connection of Removable Media to a BES Cyber Asset.

As a method to detect malicious code, entities may choose to use Removable Media with on-board malicious code detection tools. For these tools, the Removable Media are still used in conjunction with a Cyber Asset to perform the detection. For Section 5.3.1, the Cyber Asset used to perform the malicious code detection must be outside of the BES Cyber System.

Requirement R3:

The intent of CIP-003-~~57~~, Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Reliability Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that ~~this~~the CIP Senior Manager will play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-~~57~~, Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the intent is to afford the Responsible Entity ~~should have~~ significant flexibility to adapt this requirement to ~~their~~its existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. ~~In~~ such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records ~~provides~~shows a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up-~~to~~date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or the individual is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

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

Rationale for Requirement R1:

One or more security policies enable effective implementation of the ~~standard's~~ requirements of the cyber security Reliability Standards. The purpose of policies is to provide a management and governance foundation for all requirements that apply to ~~personnel who have authorized electronic access and/or authorized unescorted physical access to its~~ a Responsible Entity's BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the ~~standard's~~ requirements.

Annual review and approval of the cyber security ~~policy~~policies ensures that the ~~policy~~ is policies are kept ~~up to~~-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for Requirement R2:

In response to FERC Order No. 791, Requirement R2 requires entities to develop and implement cyber security plans to meet specific security control objectives for assets containing low impact BES Cyber System(s). The cyber security plan(s) covers five subject matter areas: (1) cyber security awareness; (2) physical security controls; (3) electronic access controls; (4) Cyber Security Incident response; and (5) Transient Cyber Asset and Removable Media Malicious Code Risk Mitigation. This plan(s), along with the cyber security policies required under Requirement R1, Part 1.2, provides a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Considering the varied types of low impact BES Cyber Systems across the BES, Attachment 1 provides Responsible Entities flexibility on how to apply the security controls to meet the security objectives. Additionally, because many Responsible Entities have multiple-impact rated BES Cyber Systems, nothing in the requirement prohibits entities from using their high and medium impact BES Cyber System policies, procedures, and processes to implement security controls required for low impact BES Cyber Systems, as detailed in Requirement R2, Attachment 1.

Responsible Entities will use their identified assets containing low impact BES Cyber System(s) (developed pursuant to CIP-002) to substantiate the sites or locations associated with low impact BES Cyber System(s). However, there is no requirement or compliance expectation for Responsible Entities to maintain a list(s) of individual low impact BES Cyber System(s) and their associated cyber assets or to maintain a list of authorized users.

Rationale for

~~One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized~~

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~~unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.~~

~~The language in Requirement R2, Part 2.3 "... for external routable protocol connections and Dial-up Connectivity ..." was included to acknowledge the support given in FERC Order 761, paragraph 87, for electronic security perimeter protections "of some form" to be applied to all BES Cyber Systems, regardless of impact. Part 2.3 uses the phrase "external routable protocol connections" instead of the defined term "External Routable Connectivity," because the latter term has very specific connotations relating to Electronic Security Perimeters and high and medium impact BES Cyber Systems. Using the glossary term "External Routable Connectivity" in the context of Requirement R2 would not be appropriate because Requirement R2 is limited in scope to low impact BES Cyber Systems.~~

Modifications to Sections 2 and 3 of Attachment 1 (Requirement R2): Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 73 of FERC Order No. 822, the Commission directed NERC to modify "...the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6...to provide needed clarity to the definition

and eliminate ambiguity surrounding the term ‘direct’ as it is used in the proposed definition...within one year of the effective date of this Final Rule.”

The revisions to Section 3 incorporate select language from the LERC definition into Attachment 1 and focus the requirement on implementing electronic access controls for asset(s) containing low impact BES Cyber System(s). This change requires the Responsible Entity to permit only necessary inbound and outbound electronic access when using a routable protocol entering or leaving the asset between low impact BES Cyber System(s) and a Cyber Asset(s) outside the asset containing low impact BES Cyber system(s). When this communication is present, Responsible Entities are required to implement electronic access controls unless that communication meets the following exclusion language (previously in the definition of LERC) contained in romanette (iii): “not used for time-sensitive protection or control functions between intelligent electronic devices (e.g. communications using protocol IEC TR-61850-90-5 R-GOOSE)”.

The revisions to Section 2 of Attachment 1 complement the revisions to Section 3; consequently, the requirement now mandates the Responsible Entity control physical access to “the Cyber Asset(s), as specified by the Responsible Entity, that provide electronic access control(s) implemented for Section 3.1, if any.” The focus on electronic access controls rather than on the Low Impact BES Cyber System Electronic Access Points (LEAPs) eliminates the need for LEAPs.

Given these revisions to Sections 2 and 3, the NERC Glossary terms: Low Impact External Routable Connectivity (LERC) and Low Impact BES Cyber System Electronic Access Point (LEAP) will be retired.

Rationale for Section 5 of Attachment 1 (Requirement R2):

Requirement R2 mandates that entities develop and implement one or more cyber security plan(s) to meet specific security objectives for assets containing low impact BES Cyber System(s). In Paragraph 32 of FERC Order No. 822, the Commission directed NERC to “...provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability.” Transient devices are potential vehicles for introducing malicious code into low impact BES Cyber Systems. Section 5 of Attachment 1 is intended to mitigate the risk of malware propagation to the BES through low impact BES Cyber Systems by requiring entities to develop and implement one or more plan(s) to address the risk. The cyber security plan(s) along with the cyber security policies required under Requirement R1, Part 1.2, provide a framework for operational, procedural, and technical safeguards for low impact BES Cyber Systems.

Rationale for Requirement

~~Review and approval of the cyber security policy at least every 15 calendar months ensures that the policy is kept up-to-date and periodically reaffirms management’s commitment to the protection of its BES Cyber Systems.~~

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~~Rationale for~~ R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the Glossary of Terms used in NERC Reliability Standards so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the ~~senior manager~~CIP Senior Manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for Requirement R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

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~~Version History~~

Version	Date	Action	Change Tracking
~~1~~	~~1/16/06~~	~~R3.2 — Change “Control Center” to “control center.”~~	~~3/24/06~~
~~2~~	~~9/30/09~~	~~Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.~~	
~~3~~	~~12/16/09~~	~~Updated version number from 2 to 3. Approved by the NERC Board of Trustees.~~	
~~3~~	~~3/31/10~~	~~Approved by FERC.~~	
~~4~~	~~1/24/11~~	~~Approved by the NERC Board of Trustees.~~	~~Update to conform to changes to CIP-002-4 (Project 2008-06)~~
~~5~~	~~11/26/12~~	~~Adopted by the NERC Board of Trustees.~~	~~Modified to coordinate with other CIP standards and to revise format to use RBS Template.~~
~~5~~	~~11/22/13~~	~~FERC Order issued approving CIP-003-5.~~	
~~5~~	~~7/9/14~~	~~FERC Letter Order issued approving VRFs and VSLs revisions to certain CIP standards.~~	~~CIP-003-5 Requirements R1 and R2 eliminated redundant language in VSLs.~~

A. Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

EOP-004-4 is being posted for a 10-day final ballot period.

<u>Completed Actions</u>	<u>Date</u>
<u>Standards Committee approved Standard Authorization Request (SAR) for posting</u>	<u>07/15/2015</u>
<u>SAR posted for comment</u>	<u>07/21/2015 – 08/19/2015</u>
<u>45-day formal comment period with ballot</u>	<u>07/25/2016 – 09/08/2016</u>
<u>45-day formal comment period with additional ballot</u>	<u>11/18/2016 – 01/09/2016</u>
<u>10-day final ballot period</u>	<u>01/24/2017 – 02/02/2017</u>

<u>Anticipated Actions</u>	<u>Date</u>
<u>NERC Board (Board) adoption</u>	<u>February 2017</u>

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.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-~~34~~
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following ~~functional entities~~Functional Entities will be collectively referred to as “Responsible Entity.”

4.1.1. Reliability Coordinator

4.1.2. Balancing Authority

4.1.3. Transmission Owner

4.1.4. Transmission Operator

4.1.5. Generator Owner

4.1.6. Generator Operator

4.1.7. Distribution Provider

~~5.—~~**Effective Dates:** See the Implementation Plan for ~~the Revised Definition of “Remedial Action Scheme”~~

~~5.—~~**6.—Background:**

~~6.5.~~ NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:
-4.

- ~~1. CIP-001 could be merged with EOP-004 to eliminate redundancies.~~
- ~~2. Acts of sabotage have to be reported to the DOE as part of EOP-004.~~
- ~~3. Specific references to the DOE form need to be eliminated.~~
- ~~4. EOP-004 had some ‘fill in the blank’ components to eliminate.~~

~~The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.~~

~~The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.~~

~~The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.~~

B. ~~B.~~ Requirements and Measures

R1. ~~R1.~~ Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-~~2-34~~ Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M1. ~~M1.~~ Each Responsible Entity will have a dated event reporting Operating Plan that includes, ~~but is not limited to the~~ protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-~~34~~ Attachment 1 and in accordance with the entity responsible for reporting.

R2. ~~R2.~~ Each Responsible Entity shall report events specified in EOP-004-4 Attachment 1 to the entities specified per their event reporting Operating Plan ~~within by the later of~~ 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity’s next business day ~~if the event occurs on a weekend (which is recognized to be 4 PM(4 p.m. local time on Friday to 8 AM Monday local time). will be considered the end of the business day).~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

M2. ~~M2.~~ Each Responsible Entity will have as evidence of reporting an event, to the entities specified per their event reporting Operating Plan either a copy of the

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completed EOP-004-~~34~~ Attachment 2 form or a DOE-OE-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted ~~within by the later of~~ 24 hours of recognition of meeting ~~the an~~ event type threshold for reporting or by the end of the Responsible Entity's next business day ~~if the event occurs on a weekend (which is recognized to be (4 PM p.m. local time on Friday to 8 AM Monday local time). (R2) will be considered the end of the business day).~~

~~R3. Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]~~

~~M3. Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)~~

C. ~~C.~~ Compliance

1. ~~1.~~ Compliance Monitoring Process

1.1. ~~1.1~~ Compliance Enforcement Authority:

~~The Regional Entity shall serve as the “Compliance Enforcement Authority (CEA) unless the applicable” means NERC or the Regional Entity, or any entity is owned, operated, or controlled as otherwise designated by the Regional Entity. In such cases the ERO an Applicable Governmental Authority, in their respective roles of monitoring and/or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.~~

1.2. ~~1.2~~ Evidence Retention:

The Responsible 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 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.

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- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements ~~s~~ R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements ~~s~~ R2, ~~R3~~ and Measure M2, ~~M3~~.

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

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

1.3. ~~1.3~~—Compliance Monitoring and Enforcement ~~Processes~~Program

~~Compliance Audit~~

~~Self-Certification~~

~~Spot-Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~1.4~~—Additional Compliance Information

~~None~~

~~Table of Compliance Elements~~

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 #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	4. ~~Operations Planning~~	5. ~~Lower~~	The Responsible Entity had an <u>event reporting</u> Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an <u>event reporting</u> Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an <u>event reporting</u> Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an <u>event reporting</u> Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to include an event report in the Operating Plan.
R2.	6. ~~Operations Assessment~~	7. ~~Medium~~	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients ~~more than~~ <u>up to</u> 24 hours ~~but less than or equal to 36 hours~~ after ~~meeting an event threshold~~ <u>the timing requirement</u>	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~36~~ <u>24</u> hours but less than or equal to 48 hours after ~~meeting an event threshold~~ <u>the timing requirement</u>	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to ~~60~~ <u>72</u> hours after ~~meeting an event threshold~~ <u>the timing requirement</u>	The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than ~~60~~ <u>72</u> hours after ~~meeting an event threshold~~ <u>the timing requirement</u> for ~~reporting~~ <u>submitting</u> OR

R #	2. Time Horizon	3. VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			for ~~reportingsubmittal~~ . OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours- <u>or by the end of the next business day, as applicable.</u>	<u>requirement</u> for ~~reportingsubmittal~~ . OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours- <u>or by the end of the next business day, as applicable.</u>	<u>requirement</u> for ~~reportingsubmittal~~ . OR The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours- <u>or by the end of the next business day, as applicable.</u>	The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours- <u>or by the end of the next business day, as applicable.</u> OR The Responsible Entity failed to submit a report on an event in EOP ~~4~~ Attachment 1

~~8.~~ <u>R3</u>	~~9.~~ <u>Operations Planning</u>	~~10.~~ <u>Medium</u>	~~11.~~ <u>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</u> ~~12.~~ <u>OR</u> ~~13.~~ <u>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</u>	~~14.~~ <u>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</u> ~~15.~~ <u>OR</u> ~~16.~~ <u>The Responsible Entity validated 50% and less than 75% of the contact information contained in the</u>	~~17.~~ <u>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</u> ~~18.~~ <u>OR</u> ~~19.~~ <u>The Responsible Entity validated 25% and less than 50% of the contact information contained in the</u>	~~20.~~ <u>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</u> ~~21.~~ <u>OR</u> ~~22.~~ <u>The Responsible Entity validated less than 25% of the contact information contained in the Operating Plan.</u>

R #	2. ~~Time Horizon~~	3. ~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~Operating Plan.~~	~~Operating Plan.~~	

~~D.~~D. Regional Variances

None.

~~E.~~ Interpretations~~None.~~~~F.~~ References~~Guideline and Technical Basis (attached)~~

E. Associated Documents

[Link to the Implementation Plan and other important associated documents.](#)

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written ~~Event Report~~event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Rationale for Attachment 1:

System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.

Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: “Any medium that allows two or more individuals to interact, consult, or exchange information.” The NERC Glossary of Terms defines Alternative Interpersonal Communication as: “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.”

Complete loss of monitoring or control capability at a BES control center: Language revisions to: “Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more” provides clarity to the “Threshold for Reporting” and better aligns with the ERO Event Analysis Process.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in ~~actions~~ action(s) to avoid a BES Emergency.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of ~~a~~ its Facility	~~BA~~ , TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action. <u>It is not necessary to report theft unless it degrades normal operation of its Facility.</u>
Physical threats to ~~a~~ its Facility	~~BA~~ , TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at ~~a~~ Facility. ~~Do not report theft unless it degrades normal operation of aits Facility.~~
Physical threats to ~~a~~ its BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at ~~a~~ its BES control center.
~~BES Emergency requiring public~~ Public appeal for load reduction <u>resulting from a BES Emergency</u>	~~Initiating entity is responsible for reporting~~ BA	Public appeal for load reduction ~~event~~ <u>to maintain continuity of the BES.</u>
~~BES Emergency requiring system~~ System-wide voltage reduction <u>resulting from a BES Emergency</u>	~~Initiating entity is responsible for reporting~~ TOP	System-wide voltage reduction of 3% or more.

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Event Type	Entity with Reporting Responsibility	Threshold for Reporting
~~BES Emergency requiring manual firm load shedding~~	~~Initiating entity is responsible for reporting~~	~~Manual firm load shedding ≥ 100 MW.~~
<u>Firm load shedding resulting from a BES Emergency resulting in automatic firm load shedding</u>	~~DP, Initiating RC, BA, or TOP~~	~~Automatic firm~~ <u>Firm</u> load shedding ≥ 100 MW (~~via manual or automatic undervoltage or underfrequency load shedding schemes, or RAS).~~
~~Voltage~~ <u>BES Emergency resulting in voltage deviation on a Facility</u>	TOP	~~Observed within its area a~~ <u>A</u> voltage deviation of ~~±~~ <u>≥</u> 10% of nominal voltage sustained for ≥ 15 continuous minutes.
~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~	RC	~~Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).~~
~~Loss~~ <u>Uncontrolled loss of firm load resulting from a BES Emergency</u>	BA, TOP, DP	~~Loss~~ <u>Uncontrolled loss</u> of firm load for ≥ 15 ~~Minutes~~ <u>minutes from a single incident:</u> ≥ 300 MW for entities with previous year's <u>peak</u> demand ≥ 3,000 MW OR ≥ 200 MW for all other entities

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island $\geq$ 100 MW
Generation loss	BA, ~~GOP~~	Total generation loss, within one minute, of: $\geq$ 2,000 MW ~~for entities~~ in the Eastern ~~or~~ Western ~~Interconnection~~ ~~OR~~ ~~$\geq$ 1,000 MW for entities in the ERCOT~~ or Quebec Interconnection <u>OR</u> <u>$\geq$ 1,400 MW in the ERCOT Interconnection</u> <u>Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources.</u>
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power (<u>LOOP</u>) affecting a nuclear generating station per the Nuclear Plant Interface Requirements ~~s~~
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES ~~Elements~~ <u>Facilities</u> caused by a common disturbance (excluding successful automatic reclosing).

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Unplanned <u>evacuation of its</u> BES control center ~~evacuation~~	RC, BA, TOP	Unplanned evacuation from <u>its</u> BES control center facility for 30 continuous minutes or more.
Complete loss of ~~voice communication~~ <u>Interpersonal Communication and Alternative Interpersonal Communication</u> capability <u>at its staffed BES control center</u>	RC, BA, TOP	Complete loss of ~~voice communication~~ <u>Interpersonal Communication and Alternative Interpersonal Communication</u> capability affecting <u>its staffed</u> BES control center for 30 continuous minutes or more.
Complete loss of monitoring <u>or control</u> capability <u>at its staffed BES control center</u>	RC, BA, TOP	Complete loss of monitoring <u>or control</u> capability ~~affecting at its staffed~~ BES control center for 30 continuous minutes or more ~~such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.~~

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form	
Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780. <u>Option 1. Also submit to other applicable organizations per Requirement R1 "... (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."</u>	
Task	Comments
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:
3.	Did the event originate in your system? Yes ☐ No ☐ Unknown ☐
4.	Event Identification and Description: (Check applicable box) ☐ Damage or destruction of a Facility ☐ Physical ~~Threat~~ to ~~its~~ Facility ☐ Physical ~~Threat~~ to ~~its~~ BES control center ☐ BES Emergency: ☐ ~~firm load shedding~~ ☐ public appeal for load reduction ☐ ~~s~~System-wide voltage reduction ☐ ~~manual firm load shedding~~ ☐ ~~automatic firm load shedding~~ ☐ ~~Voltage~~ ☐ ~~voltage~~ deviation on a Facility ☐ ~~IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)~~ ☐ ~~Loss~~ ☐ ~~uncontrolled loss~~ of firm load ☐ System separation (<u>islanding</u>) ☐ Generation loss ☐ Complete loss of off-site power to a nuclear generating plant (grid supply) ☐ Transmission loss Written description (optional):

EOP-004 Attachment 2: Event Reporting Form

Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446-9780, Option 1. Also submit to other applicable organizations per Requirement R1 "... (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."

Task	Comments
☐ ~~unplanned~~ Unplanned evacuation of its BES control center ~~evacuation~~ ☐ Complete loss of ~~voice~~ ~~communication~~ Interpersonal Communication and Alternative Interpersonal Communication capability <u>at its staffed BES control center</u> ☐ Complete loss of monitoring ~~or control~~ capability <u>at its staffed BES control center</u>	

Version History

<u>Version</u>	<u>Date</u>	<u>Action</u>	<u>Change Tracking</u>
<u>2</u>		<u>Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.</u>	<u>Revision to entire standard (Project 2009-01)</u>
<u>2</u>	<u>November 7, 2012</u>	<u>Adopted by the NERC Board of Trustees</u>	
<u>2</u>	<u>June 20, 2013</u>	<u>FERC approved</u>	
<u>3</u>	<u>November 13, 2014</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS</u>
<u>3</u>	<u>November 19, 2015</u>	<u>FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.</u>	

Guideline and Technical Basis

~~Distribution Provider Applicability Discussion~~

~~The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.~~

Multiple Reports for a Single Organization

For entities that have multiple registrations, the ~~DSR SDT intends~~requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

~~Summary of Key Concepts~~

~~The DSR SDT identified the following principles to assist them in developing the standard:~~

- ~~• Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System~~
- ~~• Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements~~
- ~~• Establish clear criteria for reporting~~
- ~~• Establish consistent reporting timelines~~
- ~~• Provide clarity around who will receive the information and how it will be used~~

~~23.~~

EOP-004-3 — Event Reporting

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

24. Data Gathering

- 25.** The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-3 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-3 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

Law Enforcement Reporting

The reliability objective of EOP-004-34 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events

EOP-004-3 — Event Reporting Supplemental Material

that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry
- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

~~Present expectations of the industry under CIP-001-1a:~~

~~It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have led to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.~~

~~Coordination of Local and State Law Enforcement Agencies with the FBI~~

EOP-004-3 — Event Reporting Supplemental Material

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

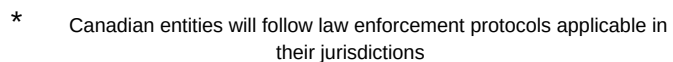
Coordination of Local and Provincial Law Enforcement Agencies with the RCMP

A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

A Reporting Process Solution — EOP-004

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Entity Experiencing An Event in Attachment 1



**Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01)–
Reporting Concepts****Introduction**

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real time operating notifications for the types of events covered by CIP-001 and EOP-004. The real time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002 Capacity and Energy Emergencies). These standards deal exclusively with after the fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections:

Summary of Concepts and Assumptions:***The Standard:***

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

EOP-004-3 — Event Reporting Supplemental Material***Discussion of Disturbance Reporting***

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

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 reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: "... the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event."

EOP-004-3 — Event ReportingSupplemental Material

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

Potential Uses of Reportable Information

~~Event analysis~~General situational awareness, correlation of data, ~~and~~ trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional ~~e~~Entities to report the incidents and provide ~~known~~ information known at the time of the report. Further data gathering necessary for ~~event~~ analysis is provided for under the ~~Events~~ERO Event Analysis Program and the NERC Rules of Procedure. ~~Other entities (e.g., NERC, Law Enforcement, etc) will be responsible for performing the analyses.~~ The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Collection of Reportable Information or “One-stop shopping”

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE 417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

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~~adoption, the text from the rationale text boxes was moved to this section.

Rationale for R1:

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective.

The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

EOP-004-3 — Event Reporting Supplemental Material**Rationale for R2:**

~~Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-3 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.~~

Rationale for R3:

~~Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.~~

Rationale for EOP-004 Attachment 1:

~~The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:~~

~~“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.)”~~

~~The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.~~

EOP-004-3 — Event Reporting Supplemental Material~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~2~~		~~Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.~~	~~Revision to entire standard (Project 2009-01)~~
~~2~~	~~November 7, 2012~~	~~Adopted by the NERC Board of Trustees~~	
~~2~~	~~June 20, 2013~~	~~FERC approved~~	
~~3~~	~~November 13, 2014~~	~~Adopted by the NERC Board of Trustees~~	~~Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS~~
~~3~~	~~November 19, 2015~~	~~FERC Order issued approving EOP-004-3. Docket No. RM15-13-000.~~	

A. Introduction

1. **Title:** System Restoration from Blackstart Resources
2. **Number:** EOP-005-~~23~~
3. **Purpose:** Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ~~assure~~ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

4.1. Functional Entities:

- 4.1.1. Transmission Operators-
- 4.1.2. Generator Operators-
- 4.1.3. Transmission Owners identified in the Transmission Operators restoration plan-
- 4.1.4. Distribution Providers identified in the Transmission Operators restoration plan-

~~1. **Proposed Effective Date*:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.~~

~~5. **Effective Date:** See the Implementation Plan for EOP-005-3.~~

~~6. **Standard-Only Definition:** None~~

B. Requirements and Measures

- R1. Each Transmission Operator shall ~~have~~develop and implement a restoration plan approved by its Reliability Coordinator. ~~The restoration plan shall allow for restoring~~be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the ~~shut down~~shutdown area ~~to service~~, to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart Resource is located within the Transmission Operator's System. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*
 - 1.1. ~~R1.1.~~ Strategies for ~~system~~System restoration that are coordinated with ~~the~~its Reliability Coordinator's high level strategy for restoring the Interconnection.
 - 1.2. ~~R1.2.~~ A description of how all Agreements or mutually ~~agreed~~ upon procedures or protocols for off-site power requirements of nuclear power plants, including priority of restoration, will be fulfilled during System restoration.

- 1.3. ~~R1.3.~~ Procedures for restoring interconnections with other Transmission Operators under the direction of ~~the~~its Reliability Coordinator.
- 1.4. ~~R1.4.~~ Identification of each Blackstart Resource and its characteristics including but not limited to the following: the name of the Blackstart Resource, location, megawatt and megavar capacity, and type of unit.

~~R1.5.—~~

- 1.5. Identification of Cranking Paths and initial switching requirements between each Blackstart Resource and the unit(s) to be started.
- 1.6. ~~R1.6.~~ Identification of acceptable operating voltage and frequency limits during restoration.

~~*Mandatory BC Effective Date: August 1, 2015~~

- 1.7. ~~R1.7.~~ Operating Processes to reestablish connections within the Transmission Operator's System for areas that have been restored and are prepared for reconnection.
- 1.8. ~~R1.8.~~ Operating Processes to restore Loads required to restore the System, such as station service for substations, units to be restarted or stabilized, the Load needed to stabilize generation and frequency, and provide voltage control.
- 1.9. ~~R1.9.~~ Operating Processes for transferring ~~authority~~operations back to the Balancing Authority in accordance with ~~the~~its Reliability Coordinator's criteria.

~~M1.~~ Each Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator and will have evidence, such as operator logs, voice recordings or other operating documentation, voice recordings or other communication documentation to show that its restoration plan was implemented for times when a Disturbance has occurred, in accordance with Requirement R1.

~~R2.~~ Each Transmission Operator shall provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan. [Violation Risk Factor = Medium] [Time Horizon ~~= Operations Planning~~
= Operations Planning]

~~M2.~~ Each Transmission Operator shall have evidence such as dated electronic receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan in accordance with Requirement R2.

~~R3.~~ Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator annually on a mutually ~~agreed~~, predetermined schedule. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

~~R3.1. If there are no changes to the previously~~ ~~M3.~~ Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories,

dated electronic receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan, the Transmission Operator shall confirm annually on a predetermined schedule to its Reliability Coordinator that it has reviewed its restoration plan and no changes were necessary. (Retirement approved by FERC effective January 21, 2014.) in accordance with Requirement R3.

~~R4.~~ Each Transmission Operator shall update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R4.1R4.~~ Each Transmission Operator shall submit its revised restoration plan to its Reliability Coordinator for approval within the same 90 calendar day period, when the revision would change its ability to implement its restoration plan, as follows: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2. Prior to implementing a planned permanent BES modification subject to its Reliability Coordinator approval requirements per EOP-006.

M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, dated electronic receipts, or registered mail receipts, that it has submitted the revised restoration plan to its Reliability Coordinator in accordance with Requirement R4.

R5. Each Transmission Operator shall have a copy of its latest Reliability Coordinator approved restoration plan within its primary and backup control rooms so that it is available to all of its System Operators prior to its implementation effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan, in electronic or hardcopy format, in its primary and backup control rooms and available to its System Operators prior to its effective date in accordance with Requirement R5.

R6. Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed at least once every five years ~~at a minimum~~. Such analysis, simulations or testing shall verify: *[Violation Risk Factor = Medium] [Time Horizon = Long-term Planning]*

6.1. ~~R6.1.~~ The capability of Blackstart Resources to meet the Real and Reactive Power requirements of the Cranking Paths and the dynamic capability to supply initial Loads.

6.2. ~~R6.2.~~ The location and magnitude of Loads required to control voltages and frequency within acceptable operating limits.

~~R6.3.~~

6.3. The capability of generating resources required to control voltages and frequency within acceptable operating limits.

M6. ~~R7.~~ Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, each affected Each Transmission Operator shall implement have documentation, such as power flow outputs, that it has verified that its latest restoration plan. If the restoration plan cannot be executed as expected the Transmission Operator shall utilize will accomplish its restoration strategies to facilitate restoration. [Violation Risk Factor = High] [Time Horizon = Real-time Operations]

intended function ~~R8.~~ Following a Disturbance in which one or more areas of the BES shuts down and the use of Blackstart Resources is required to restore the shut down area to service, the Transmission Operator shall resynchronize area(s) with neighboring Transmission Operator area(s) only with the authorization of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator. [Violation Risk Factor = High] [Time Horizon = Real-time Operations] Requirement R6.

R9R7. Each Transmission Operator shall have Blackstart Resource testing requirements to verify that each Blackstart Resource is capable of meeting the requirements of its restoration plan. These Blackstart Resource testing requirements shall include: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

7.1. ~~R9.1.~~ The frequency of testing such that each Blackstart Resource is tested at least once every three calendar years.

7.2. ~~R9.2.~~ A list of required tests including:

~~R9.2.1.~~

7.2.1. The ability to start the unit when isolated with no support from the BES or when designed to remain energized without connection to the remainder of the System.

7.2.2. ~~R9.2.2.~~ The ability to energize a bus. If it is not possible to energize a bus during the test, the testing entity must affirm that the unit has the capability to energize a bus such as verifying that the breaker close coil relay can be energized with the voltage and frequency monitor controls disconnected from the synchronizing circuits.

7.3. ~~R9.3.~~ The minimum duration of each of the required tests.

M7. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R7.

R8. ~~R10.~~ Each Transmission Operator shall include within its operations training program, annual System restoration training for its System Operators to assure the proper execution of its restoration plan. This training program shall include training on the following: [Violation Risk Factor = Medium] [Time Horizon = ~~Operations Planning~~ Operations Planning]

~~R10.1.~~

8.1. System restoration plan including coordination with ~~the~~its Reliability Coordinator and Generator Operators included in the restoration plan.

8.2. ~~R10.2.~~ Restoration priorities.

8.3. ~~R10.3.~~ Building of cranking paths.

8.4. ~~R10.4.~~ Synchronizing (re-energized sections of the System).

8.5. Transition of Demand and resource balance within its area to the Balancing Authority.

M8. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R8.

R9.

~~R11.~~ Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every two calendar years to their field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M9. Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R9.

~~R10. R12.~~ Each Transmission Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M10. Each Transmission Operator shall have evidence that it participated in its Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R10.

~~R11. R13.~~ Each Transmission Operator and each Generator Operator with a Blackstart Resource shall have written Blackstart Resource Agreements or mutually agreed upon procedures or protocols, specifying the terms and conditions of their arrangement. Such Agreements shall include references to the Blackstart Resource testing requirements. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M11. Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R11.

~~R12. R14.~~ Each Generator Operator with a Blackstart Resource shall have documented procedures for starting each Blackstart Resource and energizing a bus. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M12. Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R12.

~~R13. R15.~~ Each Generator Operator with a Blackstart Resource shall notify its Transmission Operator of any known changes to the capabilities of that Blackstart Resource affecting the ability to meet the Transmission Operator's restoration plan within 24 hours following such change. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M13. Each Generator Operator with a Blackstart Resource shall provide evidence, such as dated electronic receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within 24 hours of such changes in accordance with Requirement R13.

~~R14. R16.~~ Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. ~~R16.1.~~ Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement ~~R9~~R7.

14.2. ~~R16.2.~~ Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

M14. Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R14.

R15.

~~R17.~~ Each Generator Operator with a Blackstart Resource shall provide a minimum of two hours of training every two calendar years to each of its operating personnel responsible for the startup of its Blackstart Resource generation units and energizing a bus. The training program shall include training on the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

15.1. ~~R17.1.~~ System restoration plan including coordination with the Transmission Operator.

~~R17.2.~~ The procedures documented in Requirement ~~R14.~~

~~R18.~~ Each Generator Operator shall participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

B. Measures

~~M1.~~ Each Transmission Operator shall have a dated, documented System

~~restoration plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator as shown with the documented approval from its Reliability Coordinator.~~

~~M2. Each Transmission Operator shall have evidence such as e-mails with receipts or registered mail receipts that it provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan in accordance with Requirement R2.~~

~~M3. Each Transmission Operator shall have documentation such as a dated review signature sheet, revision histories, e-mails with receipts, or registered mail receipts, that it has annually reviewed and submitted the Transmission Operator's restoration plan to its Reliability Coordinator in accordance with Requirement R3.~~

~~M4. Each Transmission Operator shall have documentation such as dated review signature sheets, revision histories, e-mails with receipts, or registered mail receipts, that it has updated its restoration plan and submitted it to its Reliability Coordinator in accordance with Requirement R4.~~

~~M5. Each Transmission Operator shall have documentation that it has made the latest Reliability Coordinator approved copy of its restoration plan available in its primary and backup control rooms and its System Operators prior to its implementation date in accordance with Requirement R5.~~

~~M6. Each Transmission Operator shall have documentation such as power flow outputs, that it has verified that its latest restoration plan will accomplish its intended function in accordance with Requirement R6.~~

~~M7. If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it implemented its restoration plan or restoration plan strategies in accordance with Requirement R7.~~

~~M8. If there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service, each Transmission Operator involved in such an event shall have evidence, such as voice recordings, e-mail, dated computer printouts, or operator logs, that it resynchronized shut down areas in accordance with Requirement R8.~~

~~M9. Each Transmission Operator shall have documented Blackstart Resource testing requirements in accordance with Requirement R9.~~

~~M10. Each Transmission Operator shall have an electronic or hard copy of the training program material provided for its System Operators for System restoration training in accordance with Requirement R10.~~

- ~~M11.~~ Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall have an electronic or hard copy of the training program material provided to their field switching personnel for System restoration training and the corresponding training records including training dates and duration in accordance with Requirement R11.
- 15.2. ~~M12.~~ Each Transmission Operator shall have evidence, such as training records, that it participated in the Reliability Coordinator's restoration drills, exercises, or simulations as requested in accordance with Requirement R12.
- ~~M13.~~ Each Transmission Operator and Generator Operator with a Blackstart Resource shall have the dated Blackstart Resource Agreements or mutually agreed upon procedures or protocols in accordance with Requirement R13.
- ~~M14.~~ Each Generator Operator with a Blackstart Resource shall have dated documented procedures on file for starting each unit and energizing a bus in accordance with Requirement R14.
- ~~M15.~~ Each Generator Operator with a Blackstart Resource shall provide evidence, such as e-mails with receipts or registered mail receipts, showing that it notified its Transmission Operator of any known changes to its Blackstart Resource capabilities within twenty four hours of such changes in accordance with Requirement R15.
- ~~M16.~~ Each Generator Operator with a Blackstart Resource shall maintain dated documentation of its Blackstart Resource test results and shall have evidence such as e-mails with receipts or registered mail receipts, that it provided these records to its Reliability Coordinator and Transmission Operator when requested in accordance with Requirement R16.
- ~~M17.~~M15. Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup, energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement ~~R17~~R15.
- R16.~~M18~~ Each Generator Operator shall participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- M16. Each Generator Operator shall have evidence, ~~such as dated training records,~~ that it participated in ~~the its~~ Reliability Coordinator's restoration drills, exercises, or simulations if requested to do so in accordance with Requirement ~~R18~~R16.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: Regional Entity

~~The British Columbia Utilities Commission.~~

~~1.1. Compliance Monitoring Period and Reset Time Frame~~

Not applicable.

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits Self-

Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

“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.

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

- Approved restoration plan and any restoration plans in ~~force~~effect since the last compliance audit for Requirement R1, Measure M1.
- Provided the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the ~~implementation~~effective date of the plan for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- Submission of the Transmission Operator’s annually ~~reviewed~~ restoration plan to its Reliability Coordinator for the current calendar year and three prior calendar years for Requirement R3, Measure M3.

- Submission of ~~an updated~~ a revised restoration plan to its Reliability Coordinator for all versions for the current calendar year and the prior three calendar years for Requirement R4, Measure M4.
- The current, restoration plan approved by ~~the~~ its Reliability Coordinator and any restoration plans for the last three calendar years that was made available in its control rooms for Requirement R5, Measure M5.
- The verification results for the current, approved restoration plan and the previous approved restoration plan for Requirement R6, Measure M6.
 - ~~Implementation of its restoration plan or restoration plan strategies on any occasion for three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R7, Measure M7.~~
 - ~~Resynchronization of shut down areas on any occasion over three calendar years if there has been a Disturbance in which Blackstart Resources have been utilized in restoring the shut down area of the BES to service for Requirement R8, Measure M8.~~
- The verification process and results for the current Blackstart Resource testing requirements and the last previous Blackstart Resource testing requirements for Requirement ~~R9~~ R7, Measure ~~M9~~ M7.
- ~~Actual training~~ Training program materials or descriptions for three calendar years for Requirement ~~R10~~ R8, Measure ~~M10~~ M8.
- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement R10, Measure M10.

~~as well as one previous compliance audit period for Requirement R12, Measure M12.~~

If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found~~ compliant mitigation is complete and approved or for the time period specified above, whichever is longer. The Transmission Operator, applicable Transmission Owner, and applicable Distribution Provider 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 Operator, applicable Transmission Owner, and applicable Distribution provider 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:~~

Actual training

- ~~Training~~ program materials or descriptions and ~~actual~~ training records for three calendar years for Requirement ~~R11R9~~, Measure ~~M11M9~~.

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

The Transmission Operator and Generator Operator with a Blackstart Resource 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:

- Current Blackstart Resource Agreements and any Blackstart Resource Agreements or mutually agreed upon procedures or protocols in ~~force~~effect since its last compliance audit for Requirement ~~R13R11~~, Measure ~~M13M11~~.

The Generator Operator with a Blackstart Resource 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:

- Current documentation and any documentation in ~~force~~effect since its last compliance audit on procedures to start each Blackstart ~~Resources~~Resource and for energizing a bus for Requirement ~~R14R12~~, Measure ~~M14M12~~.
- Notification to its Transmission Operator of any known changes to its Blackstart Resource capabilities over the last three calendar years for Requirement ~~R15R13~~, Measure ~~M15M13~~.
- The verification test results for the current set of requirements and one previous set for its Blackstart Resources for Requirement ~~R16R14~~, Measure ~~M16M14~~.
- ~~Actual-training~~Training program materials and ~~actual~~ training records for three calendar years for Requirement ~~R17R15~~, Measure ~~M17M15~~.

If a Generation Operator with a Blackstart Resource is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found-compliant~~mitigation is complete and approved or for the time period specified above, whichever is longer.

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

- Records of participation in all requested Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit for Requirement ~~R18R16~~, Measure ~~M18M16~~.

If a Generation Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved or for the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last compliance audit records and all requested and submitted subsequent compliance audit records.

1.3. The Compliance Monitoring and Enforcement Authority shall keep Program
As defined in the last audit records and all requested and submitted subsequent audit recordsNERC 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. Additional Compliance Information

~~None.~~

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~
~~EOP-005-3 — System Restoration from Blackstart Resources~~

Violation Severity Levels

R.#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1.~~	~~The Transmission Operator has an approved plan but failed to comply with one of the sub-requirements within the requirement.~~	~~The Transmission Operator has an approved plan but failed to comply with two of the sub-requirements within the requirement.~~	~~The Transmission Operator has an approved plan but failed to comply with three of the sub-requirements within the requirement.~~	~~The Transmission Operator does not have an approved restoration plan.~~
~~R2~~ R1.	The Transmission Operator <u>has an approved plan but failed to provide</u> <u>comply with</u> one of the <u>requirement parts within Requirement R1</u> <u>entities identified in its approved restoration plan</u> <u>with a description of any changes to their roles and specific tasks prior to the implementation date of the plan.</u> <u>OR</u> The Transmission Operator <u>provided the information to all entities but was up to 10 calendar days late in doing so.</u>	The Transmission Operator <u>has an approved plan but failed to provide</u> <u>comply with</u> two of the <u>requirement parts within Requirement R1</u> <u>entities identified in its approved restoration plan</u> <u>with a description of any changes to their roles and specific tasks prior to the implementation date of the plan.</u> <u>OR</u> The Transmission Operator <u>provided the information to all entities but was more than 10 and less than or equal to 20 calendar days late in doing so.</u>	The Transmission Operator <u>failed to provide three of the</u> <u>has an entities identified in its approved restoration plan but failed to comply with a</u> <u>description of any changes to their roles and specific tasks prior to the implementation date of the plan.</u> <u>three or</u> <u>OR</u> The Transmission Operator <u>provided the information to all entities but was more than 20 and less than or equal to 30 calendar days late in doing so of the requirement parts within Requirement R1.</u>	The Transmission Operator <u>failed to provide four or more of the</u> <u>does not have an entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan.</u> <u>OR</u> The Transmission Operator <u>provided the information to all entities</u> <u>has an approved restoration plan, but was more than 30 calendar days late in doing so</u> <u>failed to implement the applicable requirement parts within</u>

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~~~EOP-005-3 – System Restoration from Blackstart Resources~~

~~R2.~~	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change within 30 calendar days after the pre-determined schedule. <u>failed to provide one of the entities identified in its</u> The Transmission Operator failed to update and submit its <u>approved</u> restoration plan to the <u>with a description of any changes to their roles and specific tasks prior to the effective date of the plan.</u>	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 30 and less than or equal to 60 calendar days after the pre-determined schedule. <u>The Transmission Operator failed to provide two of the entities identified in its</u> The Transmission Operator failed to update and submit its <u>approved</u> restoration plan to the <u>with a description of any changes to their roles and specific tasks prior to the effective date of the plan.</u>	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 60 and less than or equal to 90 calendar days after the pre-determined schedule. <u>The Transmission Operator failed to provide three of the entities identified in its</u> The Transmission Operator has failed to update and submit its <u>approved</u> restoration plan to the <u>with a description of any changes to their roles and specific tasks prior to the effective date of the plan.</u>	The Transmission Operator submitted the reviewed restoration plan or confirmation of no change more than 90 calendar days after the pre-determined schedule. <u>failed to provide four or more of the entities</u> The Transmission Operator has failed to update and submit its restoration plan to the <u>identified in its approved</u> <u>restoration plan with a description of any changes to their roles and specific tasks prior to the effective date of the plan.</u> <u>OR</u> <u>Transmission Operator failed to provide at least half of the entities identified in its</u>

Standard EOP-005-2 — System Restoration from Blackstart ResourcesEOP-005-3 – System Restoration from Blackstart Resources

R. #	Violation Severity			
	Lower VSL Reliability Coordinator within	Moderate VSL Reliability Coordinator within	High VSL Reliability Coordinator within	Severe VSL Reliability Coordinator within
~~R5.~~	N/A	N/A	N/A	The Transmission Operator did not make the latest Reliability Coordinator approved restoration plan available in its primary with a description of any changes to their roles and
~~R6~~ R3.	The Transmission Operator performed submitted the verification reviewed restoration plan within 30 calendar days after the required timeframe but did not comply with one of the sub-requirements mutually-agreed	The Transmission Operator performed submitted the verification within reviewed restoration plan more than 30 and less than or equal to 60 calendar days after the required timeframe but did not comply with two of the sub-	The Transmission Operator performed submitted the verification but did not complete it within the five reviewed restoration plan more than 60 and less than or equal to 90 calendar year period days after the	The Transmission Operator did not perform submitted the verification or it took reviewed restoration plan more than six 90 calendar years to completed days after the verification. OR mutually-agreed.
~~R7~~ R4.	The Transmission Operator failed to submit its revised restoration plan to its Reliability Coordinator within 90 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 91 calendar days and 120 calendar days of an unplanned permanent System BES modification.	The Transmission Operator submitted its revised restoration plan to its Reliability Coordinator between 121 calendar days and 150 calendar days of an unplanned permanent System BES modification.	The Transmission Operator did not implement has failed to submit its revised restoration plan to its Reliability Coordinator within 150 calendar days of an unplanned permanent System BES modification. OR following a Disturbance in which Blackstart Resources have been utilized in restoring The Transmission Operator failed to submit its revised

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~~~EOP-005-3 – System Restoration from Blackstart Resources~~

R. #	Violation Severity			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R8.~~	N/A	N/A	N/A	~~The Transmission Operator resynchronized without approval of the Reliability~~
~~R5.~~	N/A	N/A	N/A	~~The Transmission Operator's Blackstart Resource testing requirements do~~ Operator did not address one or more of make the sub-requirements of Requirement R9 latest Reliability Coordinator approved
~~R10~~ R6.	The Transmission Operator's training does Operator performed the verification within the required timeframe but did not address comply with one of the sub-requirements of Requirement R10 requirement parts.	The Transmission Operator's training does Operator performed the verification within the required timeframe but did not address comply with two of the sub-requirements of Requirement R10 requirement parts.	The Transmission Operator's training does Operator performed the verification but did not address three or more of the sub-requirements of Requirement R10 complete it within the required time frame.	The Transmission Operator has did not perform the verification or it took more than six calendar years to complete the verification. OR The Transmission Operator performed the verification within the required timeframe but did not comply with any of the included System restoration training in its operations training program requirement parts

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~

~~EOP-005-3 – System Restoration from Blackstart Resources~~

~~R7.~~	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by~~ <u>N/A</u>	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the~~ <u>N/A</u>	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the~~ <u>N/A</u>	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel~~ <u>The Transmission Operator's Blackstart Resource testing requirements do not address</u>

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~
~~EOP-005-3 – System Restoration from Blackstart Resources~~

R. #	Violation Severity			
	Lower VSL Requirement R11- within a two	Moderate VSL personnel- required by	High VSL personnel required by Requirement	Severe VSL required by- Requirement R11
~~R12.~~	N/A.	N/A	N/A	The Transmission Operator has failed to comply with a request for their participation from the Reliability Coordinator <u>one or more of the requirement parts of Requirement R7.</u>
~~R13~~ R8.	<u>The Transmission Operator's training does not address one of the requirement parts of Requirement R8.</u>	~~The Transmission Operator and Generator Operator with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written Blackstart Resource Agreements or mutually agreed upon procedures or protocols.~~ <u>The Transmission Operator's training does not address two of the requirement parts of Requirement R8.</u>	~~N/A~~ <u>The Transmission Operator's training does not address three or more of the requirement parts of Requirement R8.</u>	~~The Transmission Operator and Generator Operator with a Blackstart resource do~~ <u>has</u> not have a written Blackstart Resource Agreement or mutually agreed upon procedure or protocol <u>included System restoration training in its operations training program.</u>

Standard EOP-005-2 — System Restoration from Blackstart Resources**EOP-005-3 – System Restoration from Blackstart Resources**

~~R9~~ R9.	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train 5% or less of the personnel required by Requirement R9 within a two-calendar-year period.~~	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 5% and up to 10% of the personnel required by Requirement R9 within a two-calendar-year period.~~	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 10% and up to 15% of the personnel required by Requirement R9 within a two-calendar-year period.~~	~~The Transmission Operator, applicable Transmission Owner, or applicable Distribution Provider failed to train more than 15% of the personnel required by Requirement R9 within a two-calendar-year period.~~ ~~The Generator Operator does not have documented starting and bus energizing procedures.~~
~~R10~~ R10.	~~The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 24 hours but did make the notification within 48 hours.~~ ~~N/A~~	~~The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 48 hours but did make the notification within 72 hours.~~ ~~N/A~~	~~The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within 72 hours but did make the notification within 96 hours.~~ ~~N/A~~	~~The Generator Operator with a Blackstart Resource did not notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan.~~ ~~has failed to comply with a request for more than 96 hours.~~
~~R11~~ R11.	~~The GOP with a Blackstart Resource performed tests and~~ ~~N/A~~	~~The GOP with a Blackstart Resource performed~~	~~The GOP with a Blackstart Resource performed tests but~~ ~~N/A~~	~~The Transmission Operator and Generator Operator with a Blackstart Resource~~

Standard EOP-005-2 — System Restoration from Blackstart Resources
EOP-005-3 — System Restoration from Blackstart Resources

R. #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	maintained records but the records did not include all of the items in R16.1. OR The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days of the request.	maintained records but did not supply the Blackstart Resource testing records as requested for 61 days to 90 calendar days after the request with a Blackstart Resource do not reference Blackstart Resource Testing requirements in their written	either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.	perform with a Blackstart resource do not have a written Blackstart Resource tests Agreement or mutually-agreed upon procedure or protocol.
R12.	N/A	N/A	N/A	The Generator Operator does not have documented starting and bus energizing procedures for each Blackstart Resource.
R17- R13.	The Generator Operator with a Blackstart Resource did not train less than or equal to 10% notify the Transmission Operator of the personnel required by Requirement R17a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within a two-calendar year period 24 hours but did make the notification within 48 hours.	The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% notify the Transmission Operator of the personnel required by Requirement R17a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within a two-calendar year period 48 hours but did make the notification within 72 hours.	The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% notify the Transmission Operator of the personnel required by Requirement R17a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan within a two-calendar year period 72 hours but did make the notification within 96 hours.	The Generator Operator with a Blackstart Resource did not train notify the Transmission Operator of a known change in Blackstart Resource capability affecting the ability to meet the Transmission Operator's restoration plan for more than 50% of the personnel required by Requirement R17 within a two-calendar year period 96 hours.

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~~~EOP-005-3 – System Restoration from Blackstart Resources~~

~~R18.~~	~~N/A.~~	~~N/A~~	~~N/A~~	~~The Generator Operator failed to participate in the Reliability Coordinator's restoration drills, exercises, or simulations as requested by the Reliability Coordinator.~~

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~~~EOP-005-3 – System Restoration from Blackstart Resources~~

ATTACHMENT D

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~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~

E.

<u>R.#</u>	<u>Violation Severity Levels</u>			
	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R14.</u>	<u>The Generator Operator with a Blackstart Resource performed tests and maintained records but the records did not include all of the items in Requirement R14, Part 14.1.</u> <u>OR</u> <u>The Generator Operator did not supply the Blackstart Resource testing records as requested for 31 to 60 calendar days after the request.</u>	<u>The Generator Operator with a Blackstart Resource performed tests and maintained records but did not supply the Blackstart Resource testing records as requested for 61 to 90 calendar days after the request.</u>	<u>The Generator Operator with a Blackstart Resource performed tests but either did not maintain records or did not supply the Blackstart Resource testing records as requested within 91 or more calendar days after the request.</u>	<u>The Generator Operator with a Blackstart Resource did not perform Blackstart Resource tests.</u>
<u>R15.</u>	<u>The Generator Operator with a Blackstart Resource did not train less than or equal to 10% of the personnel required by Requirement R15 within a two-calendar-year period.</u>	<u>The Generator Operator with a Blackstart Resource did not train more than 10% and less than or equal to 25% of the personnel required by Requirement R15 within a two-calendar-year period.</u>	<u>The Generator Operator with a Blackstart Resource did not train more than 25% and less than or equal to 50% of the personnel required by Requirement R15 within a two-calendar-year period.</u>	<u>The Generator Operator with a Blackstart Resource did not train more than 50% of the personnel required by Requirement R15 within a two-calendar-year period.</u>

~~Standard EOP-005-2 — System Restoration from Blackstart Resources~~~~EOP-005-3 – System Restoration from Blackstart Resources~~

<u>R16.</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The Generator Operator failed to participate in its Reliability Coordinator's restoration drills, exercises, or simulations as requested by its Reliability Coordinator.</u>

D. Regional Variances

None.

E. Associated Documents[Link to the Implementation Plan and other important associated documents.](#)

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	May 2, 2007	Approved by <u>the</u> Board of Trustees	Revised
2	~~FBD~~	Revisions pursuant to Project 2006-03	Updated testing requirements Incorporated Attachment 1 into the requirements Updated Measures
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17,- 2011	Order issued by FERC approving EOP-005-2 (approval effective 5/23/11)	
2	February 7,- 2013	R3.1 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory	
2	July 1, 2013	Updated VRFs and VSLs based on June 24, 2013 approval	
2	November 21, 2013	R3.1 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
<u>3</u>	<u>February 9, 2017</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Revised</u>

Supplemental Material**Rationale**

Rationale for Requirement R4: As previously written, Requirement R4 addressed (in one sentence) two restoration plan update items that a Transmission Operator must perform: (1) the restoration plan must be updated within 90 calendar days after identifying any unplanned permanent System modifications and (2) the restoration plan must be updated prior to implementing a planned BES modification. The phrase: “... that would change the implementation of its restoration plan” appeared to apply to both types of changes. There was no time frame specified for updating the restoration plan for a planned BES modification; although one could infer that “90 calendar days” is intended to be the same time frame for both unplanned and planned modifications. Furthermore, the distinction between “System modifications” for unplanned changes and “BES modifications” for planned changes has been seen as confusing to some Responsible Entities.

The references to permanent unplanned and planned BES modifications that will change the ability to implement the RC-approved restoration plan are intended to require a Responsible Entity to submit a revised restoration plan to the RC when the modification would substantively change the TOP’s ability to implement the restoration plan or impact the RC’s ability to monitor and direct restoration efforts. The intent is not to require a TOP to submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts. Examples of instances that do not require update and submission of a restoration plan include element number changes, device changes, or administrative changes that have no significance to the implementation of the plan.

In addition, the timeframes referenced in Requirement R4, Part 4.2 for a permanent planned BES modification directs the Responsible Entity to EOP-006-2, Requirement R5.1 and EOP-006-3, Requirement R5, Part 5.1, which states that the RC shall approve or disapprove the TOPs submitted restoration plan within 30 days of receipt. This allows the Responsible Entity to coordinate submission with the RC based on the RCs specific requirements.

Rationale for Requirement R6: Dynamic simulations should simulate frequency and voltage response. It is the intent of the EOP SDT that the simulation provides for the feedback of the System performance as generation and Load are added.

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

Rationale for Requirement R9: The intent of “unique tasks” are those tasks that are defined by the Transmission Operator, the Transmission Owner, and the Distribution Provider.

A. Introduction

1. **Title:** System Restoration Coordination
2. **Number:** EOP-006-~~23~~
3. **Purpose:-** Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Reliability Coordinators-

- ~~1. **Proposed Effective Date*:** Twenty four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty four months after Board of Trustees adoption.~~
5. **Proposed Effective Date:** See the Implementation Plan for EOP-006-3.
6. **Standard-Only Definition:** None

B. Requirements and Measures

R1. Each Reliability Coordinator shall ~~have~~develop and implement a Reliability Coordinator Area restoration plan.

The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a ~~shut down~~shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and ~~it~~ its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include: *[Violation Risk Factor = High] [Time Horizon = Operations Planning, Real-time Operations]*

- ~~1.1. **R1.1.**~~ A description of the high-~~level~~ strategy to be employed during restoration events for restoring the Interconnection, including minimum criteria for meeting the objectives of the Reliability Coordinator's restoration plan.

~~**R1.2.** Operating Processes for restoring the Interconnection.~~

~~**R1.3.** Descriptions of the elements of coordination between individual Transmission Operator restoration plans.~~

~~**R1.4.** Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators.~~

- ~~1.2. **R1.5.**~~ Criteria and conditions for ~~reestablishing~~re-establishing interconnections with other Transmission Operators within its Reliability Coordinator Area, with Transmission Operators in other Reliability Coordinator Areas, and with other Reliability Coordinators.

- ~~1.3. **R1.6.**~~ Reporting requirements for the entities within the Reliability Coordinator Area

during a restoration event.

- 1.4. ~~R1.7.~~** Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area.

- 1.5. ~~R1.8.~~** Identification of the Reliability Coordinator as the primary contact for disseminating information regarding restoration to neighboring Reliability-

Coordinators, and to Transmission Operators, and Balancing Authorities within its Reliability Coordinator Area.

- ~~1.5.1.6.~~ **~~R1.9.~~** Criteria for transferring operations and authority back to the Balancing Authority.

M1. Each Reliability Coordinator shall have available a dated copy of its restoration plan and will have evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its restoration plan was implemented in accordance with Requirement R1.

- R2.** The Reliability Coordinator shall distribute its most recent Reliability Coordinator Area restoration plan to each of its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of creation or revision. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*

M2. Each Reliability Coordinator shall provide evidence such as electronic receipts, posting to a secure website with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.

- R3.** Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

M3. Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within 13 calendar months of the last review in accordance with Requirement R3.

- R4.** Each Reliability Coordinator shall review ~~their~~its neighboring Reliability Coordinator's restoration plans and provide written notification of any conflicts discovered during that review within 60 calendar days of receipt. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R44.1.~~ ~~—~~ If ~~the~~ Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved ~~in~~within 30 calendar days of receipt of written notification.

M4. Each Reliability Coordinator shall provide evidence such as dated review signature sheets or electronic receipt that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within the timing requirements of Requirement R4 and Requirement R4, Part 4.1.

- R5.** Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

~~R55.1.~~ ~~—~~ The Reliability Coordinator shall determine whether the Transmission Operator's

restoration plan is coordinated and compatible with the Reliability Coordinator's restoration plan and other Transmission Operators' restoration plans within its-

Reliability Coordinator Area. -The Reliability Coordinator shall ~~approve~~provide notification to the Transmission Operator of approval or disapproval, with stated reasons, of the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator.

- M5. Each Reliability Coordinator shall provide evidence such as a dated review signature sheet or electronic receipt that it has reviewed, approved or disapproved, and notified its Transmission Operators within 30 calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.
- R6. Each Reliability Coordinator shall have a copy of its latest restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area within its primary and backup control rooms so that it is available to all of its System Operators prior to the implementation effective date. *[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]*
- ~~R7.~~ M6. Each Reliability Coordinator shall ~~work with its affected Generator Operators, and Transmission Operators~~have documentation such as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits. If the electronic receipts that it has made the latest copy of its restoration plan ~~cannot be completed as expected the and~~copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator shall utilize its restoration plan strategies to facilitateArea available in its primary and backup control rooms and to each of its System ~~restoration.~~restoration. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*Operators prior to the effective date in accordance with Requirement R6.
- ~~R7.~~ ~~R8.~~ The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization. *[Violation Risk Factor = High] [Time Horizon = Real-time Operations]*
- R9. Each Reliability Coordinator shall include within its operations training program, annual System restoration training for its System Operators ~~to assure the proper execution of its restoration plan.~~ This training program shall address the following: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*
- 7.1. ~~R9.1.~~ The coordination role of the Reliability Coordinator; and
- 7.2. ~~R9.2. Reestablishing~~Re-establishing the Interconnection.
- M7. Each Reliability Coordinator shall have an electronic copy or hard copy of its training records available showing that it has provided training in accordance with Requirement R7.
- R8. ~~R10.~~ Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being

conducted. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]
~~= Operations Planning]~~

R10

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years.

B. Measures

~~M1. M8.~~ Each Reliability Coordinator shall have ~~available a dated copy of its restoration plan in accordance with Requirement R1.~~

~~M2.~~ Each Reliability Coordinator shall provide evidence, such as ~~e-mails with receipts, posting to a secure web site with notification to affected entities, or registered mail receipts, that its most recent restoration plan has been distributed in accordance with Requirement R2.~~

~~M3.~~ Each Reliability Coordinator shall provide evidence such as a review signature sheet, or revision histories, that it has reviewed its restoration plan within ~~13~~ calendar months of the last review in accordance with Requirement R3.

~~M4.~~ Each Reliability Coordinator shall provide evidence such as dated review signature sheets that it has reviewed its neighboring Reliability Coordinator's restoration plans and resolved any conflicts within ~~30~~ calendar days in accordance with Requirement R4.

dated

~~M5.~~ Each Reliability Coordinator shall provide evidence, such as a review signature sheet or emails, that it has reviewed, approved or disapproved, and notified its Transmission Operator's within ~~30~~ calendar days following the receipt of the restoration plan from the Transmission Operator in accordance with Requirement R5.

~~M6.~~ Each Reliability Coordinator shall have documentation such as e-mail receipts that it has made the latest copy of its restoration plan and copies of the latest approved restoration plan of each Transmission Operator in its Reliability Coordinator Area available in its primary and backup control rooms and to each of its System Operators prior to the implementation date in accordance with Requirement R6.

- ~~M7.~~ Each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, dated computer printouts, or operator logs, that it monitored and coordinated restoration progress in accordance with Requirement R7.
- ~~M8.~~ If there has been a resynchronizing of an islanded area, each Reliability Coordinator involved shall have evidence such as voice recordings, e-mail, or operator logs, that it coordinated or authorized resynchronizing in accordance with Requirement R8.
- ~~M9.~~ Each Reliability Coordinator shall have an electronic or hard copy of its training records available showing that it has provided training in accordance with Requirement R9.
- ~~M10.~~ Each Reliability Coordinator shall have evidenced documents, that it conducted two System restoration drills, exercises, or simulations per calendar year ~~and that Transmission Operators and Generator Operators included in the Reliability Coordinator's restoration plan were invited~~ in accordance with Requirement ~~R10.~~R8. And each Reliability Coordinator shall have evidence that the Reliability Coordinator requested each applicable Transmission Operator and Generator Operator to participate per Requirement R8 and Requirement R8, Part 8.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

~~The British Columbia Utilities Commission~~

~~1.1. Compliance Monitoring Period and Reset Time Frame~~

~~Not applicable.~~

~~1.2. Compliance Monitoring and Enforcement Processes:~~

~~Compliance-~~

~~Audits Self-~~

~~Certification~~

~~s-Spot~~

~~Checking~~

~~Compliance Violation-~~

~~Investigations Self-~~

~~Reporting~~

~~Complaints~~

1.3. Data Retention

"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 Reliability Coordinator~~ 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 current restoration plan and any restoration plans in ~~force~~effect since the last compliance audit for Requirement R1, Measure M1.
- Distribution of its most recent restoration plan and any restoration plans in ~~force~~effect for the current calendar year and three prior calendar years for Requirement R2, Measure M2.
- It's reviewed restoration plan for the current review period and the last three prior review periods for Requirement R3, Measure M3.
- Reviewed copies of neighboring Reliability Coordinator restoration plans for the current calendar year and the three prior calendar years for Requirement R4, Measure M4.
- The reviewed restoration plans for the current calendar year and the last three prior calendar years for Requirement R5, Measure M5.
- The current, approved restoration plan and any restoration plans in ~~force~~effect for the last three calendar years was made available in its control rooms for Requirement R6, Measure M6.
- ~~If there has been a restoration event, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R7, Measure M7.~~
- ~~If there has been a resynchronization of an islanded area, implementation of its restoration plan on any occasion over a rolling 12 month period for Requirement R8, Measure M8.~~
- Actual training program materials or descriptions for three calendar years for Requirements ~~R9-R7~~, Measure ~~M9-M7~~.

- Records of all Reliability Coordinator restoration drills, exercises, or simulations since its last compliance audit, as well as one previous compliance audit period for Requirement ~~R10R8~~, Measure ~~M10M8~~.

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

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

1.2.1.3. ~~Additional Compliance Information~~ Monitoring and Enforcement Program

~~None.~~

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.

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Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL The Reliability Coordinator	Moderate VSL The Reliability Coordinator	High VSL The Reliability Coordinator	Severe VSL The Reliability Coordinator
~~R2~~ R1.	The Reliability Coordinator distributed the most recent Reliability Coordinator Area failed to include one requirement part of Requirement R1 within its restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar	The Reliability Coordinator distributed the most recent Reliability Coordinator Area failed to include two requirement parts of Requirement R1 within its restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	The Reliability Coordinator distributed failed to include three of the most recent Reliability Coordinator Area requirements parts of Requirement R1 within its restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator distributed failed to include four or more of the requirement parts within its restoration plan. <u>OR</u> most recent The Reliability Coordinator Area had a restoration plan to entities identified in Requirement
~~R3~~ R2.	~~N/A~~ The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was more than 30 calendar days late but less than 60 calendar days late.	~~N/A~~ The Reliability Coordinator distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 60 calendar days or more late, but less than 90 calendar days late.	<u>The Reliability Coordinator</u> N/A distributed the most recent Reliability Coordinator Area restoration plan to the entities identified in Requirement R2 but was 90 or more calendar days late but less than 120 calendar days late.	The Reliability Coordinator did not review its distributed the most recent Reliability Coordinator Area restoration plan within 13 to entities identified in Requirement R2 but was 120 calendar months of the last review days or more late.

~~R3.~~	~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 60 calendar days.~~ <u>N/A</u>	~~The Reliability Coordinator did not review and resolve conflicts with the submitted restoration plans from its neighboring Reliability Coordinators within 30 calendar days but did resolve conflicts within 90 calendar days.~~ <u>N/A</u>	N/A	The Reliability Coordinator did not review ~~and resolve conflicts with the submitted its~~ restoration plans from its neighboring Reliability Coordinators <u>plan</u> within ~~30~~ <u>13</u> calendar days but did resolve conflicts within 120 calendar days <u>months of the last review.</u>
<u>R4.</u>	<u>The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt, and resolved conflicts between 31 and 60 calendar days following written notification.</u>	<u>The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts between 61 and 90 calendar days following written notification.</u>	<u>The Reliability Coordinator reviewed the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt and resolved conflicts 91 or more calendar days following written notification.</u>	<u>The Reliability Coordinator did not review the submitted restoration plans from its neighboring Reliability Coordinators within 60 calendar days of receipt.</u>

R5.	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, <u>with stated reasons for disapproval</u>, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 45 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, <u>with stated reasons for disapproval</u>, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 60 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, <u>with stated reasons for disapproval</u>, from its Transmission Operators and neighboring Reliability Coordinators within 30 calendar days of receipt but did review and approve/disapprove the plans within 90 calendar days of receipt. OR	The Reliability Coordinator did not review and approve/disapprove the submitted restoration plans, <u>with stated reasons for disapproval</u>, from its Transmission Operators and neighboring Reliability Coordinators for more than - 90 calendar days of receipt. OR The Reliability Coordinator failed to notify the Transmission Operator of its
R6.	N/A	N/A	~~The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the~~	~~The Reliability Coordinator did not have a copy of its latest restoration plan within its primary and backup control rooms prior to the implementation date.~~

R #	Violation Severity Levels			
	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
R7.	<u>The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 45 calendar days of receipt.</u> ~~N/A~~	<u>The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt, but did notify the Transmission Operator of its approval or disapproval with reasons within 60 calendar days of receipt.</u> ~~N/A~~	<u>The Reliability Coordinator failed to notify the Transmission Operator of its approval or disapproval with stated reasons for disapproval within 30 calendar days of receipt but did notify the Transmission Operator of its approval or disapproval with reasons within 90 calendar days of receipt.</u> ~~N/A~~	~~The Reliability Coordinator did not work with its affected Generator Operators and Transmission Operators as well as neighboring Reliability Coordinators to monitor restoration progress, coordinate restoration, and take actions to restore the BES frequency within acceptable operating limits.~~ <u>approval or disapproval with stated reasons for disapproval for more than 90 calendar days of receipt.</u> ~~OR~~ ~~When the restoration plan cannot be completed as expected, the Reliability Coordinator did not utilize its restoration plan strategies to facilitate System restoration.~~

~~R6.~~ <u>R6.</u>	N/A	N/A	~~N/A~~ <u>The Reliability Coordinator did not have a copy of the latest approved restoration plan of all Transmission Operators in its Reliability Coordinator Area within its primary and backup control rooms prior to the effective date.</u>	~~The Reliability Coordinator did not coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators.~~ <u>have a copy of its latest restoration plan within its primary and backup control rooms prior to</u> ~~OR~~ ~~If the resynchronization could not be completed as expected, the Reliability Coordinator did effective date.~~
<u>R7.</u>	<u>N/A</u>	<u>N/A</u>	<u>The Reliability Coordinator included the annual System restoration training within its operations training program.</u>	<u>The Reliability Coordinator did not include the annual System restoration training</u>

R.#	<u>Violation Severity Levels</u>			
	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
~~R9.~~	N/A	N/A	~~The Reliability Coordinator included the annual System restoration training within its operations training program,~~ but did not address both of the ~~sub-~~ <u>requirements</u> <u>requirement</u> <u>parts.</u>	~~The Reliability Coordinator did not include the annual System restoration training~~ within its operations training program.
~~R10~~ ~~R8.~~	~~N/A~~ ~~The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.~~	<u>The Reliability Coordinator only held one restoration drill, exercise, or simulation during the calendar year.</u> <u>OR</u> The Reliability Coordinator did not ~~invite a~~ <u>request each applicable</u> Transmission Operator or Generator Operator identified in its restoration plan to participate in a drill, exercise, or simulation ~~within~~ <u>at least once every two calendar years.</u>	N/A	The Reliability Coordinator did not hold a restoration drill, exercise, or simulation during the calendar year.

~~Standard EOP-006-2 — System Restoration Coordination~~

~~E.~~

D. Regional Variances

None.

E. Associated Documents

[Link to the Implementation Plan and other important associated documents.](#)

Supplemental Material**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~~ <u>Nov. 1, 2006</u>	Adopted by Board of Trustees	Revised
2	~~TBD~~	Revisions pursuant to Project- 2006-03	Updated Measures and- Compliance to match new Requirements
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	March 17, 2011	Order issued by FERC approving- EOP-006-2 (approval effective 5/23/11)	
2	July 1, 2013	Updated VRFs and VSLs based- on June 24, 2013 approval.	
<u>3</u>	<u>February 9, 2017</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Revised</u>
<u>3</u>	<u>January 18, 2018</u>	<u>FERC order issued approving EOP-006-3. Docket No. RM17- 12-000.</u>	

A. Introduction

1. **Title:** Loss of Control Center Functionality
2. **Number:** EOP-008-~~1~~2
3. **Purpose:** Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Reliability Coordinator.
 - 4.1.2. Transmission Operator.
 - 4.1.3. Balancing Authority.
5. ~~**Effective Date:** The first day of the first calendar quarter twenty-four months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the standard shall become effective on the first day of the first calendar quarter twenty-four months after Board of Trustees adoption.~~
5. **Effective Date:** See the Implementation Plan for EOP-008-2.
6. **Standard-Only Definition:** None

B. Requirements and Measures

- R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost. This Operating Plan for backup functionality shall include ~~the following, at a minimum:~~ *[Violation Risk Factor = Medium]* *[Time Horizon = Operations Planning]*
 - 1.1. The location and method of implementation for providing backup functionality ~~for the time it takes to restore the primary control center functionality.~~
 - 1.2. A summary description of the elements required to support the backup functionality. These elements shall include ~~, at a minimum:~~
 - 1.2.1. Tools and applications to ensure that System Operators have situational awareness of the BES.
 - 1.2.2. Data ~~communications.~~ exchange capabilities.
 - ~~1.1.1.~~ ~~Voice communications.~~
 - 1.2.3. Interpersonal Communications.
 - ~~1.2.3.~~ 1.2.4. Power source(s).
 - ~~1.2.4.~~ 1.2.5. Physical and cyber security.
 - 1.3. An Operating Process for keeping the backup functionality consistent with the

primary control center.

- 1.4. Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality.
- 1.5. A transition period between the loss of primary control center functionality and the time to fully implement the backup functionality that is less than or equal to two hours.
- 1.6. An Operating Process describing the actions to be taken during the transition period between the loss of primary control center functionality and the time to fully implement backup functionality elements identified in Requirement R1, Part 1.2. The Operating Process shall include ~~at a minimum~~:
 - 1.6.1. A list of all entities to notify when there is a change in operating locations.
 - 1.6.2. Actions to manage the risk to the BES during the transition from primary to backup functionality, as well as during outages of the primary or backup functionality.
 - 1.6.3. Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality.

~~M1.~~ Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.

R2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a copy of its current Operating Plan for backup functionality available at its primary control center and at the location providing backup functionality.
[Violation Risk Factor = Lower] [Time Horizon = Operations Planning]

~~M2.~~ Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, and in effect copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.

R3. Each Reliability Coordinator shall have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards ~~that depend on~~ are applicable to the primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during: [Violation Risk Factor = High] [Time Horizon = Operations Planning]

- Planned outages of the primary or backup facilities of two weeks or less
- Unplanned outages of the primary or backup facilities

~~M1.~~M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at

another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that are applicable to the primary control center functionality in accordance with Requirement R3.

- R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~ are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively.~~ To avoid requiring tertiary functionality, backup functionality is not required during: *[Violation Risk Factor = High] [Time Horizon = Operations Planning]*

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

- M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that are applicable to a Balancing Authority's or Transmission Operator's primary control center functionality in accordance with Requirement R4.

- R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- 5.1. An update and approval of the Operating Plan for backup functionality shall take place within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1.

- M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence that its dated, current, and in effect Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.

- R6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have primary and backup functionality that do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

- M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with

Standard EOP-008-1—2 – Loss of Control Center Functionality

Reliability Standards in accordance with Requirement R6.

R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

7.1. The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality.

7.2. The backup functionality for a minimum of two continuous hours.

M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.

R8. Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of its primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide a plan to its Regional Entity within six calendar months of the date when the functionality is lost, showing how it will re-establish primary or backup functionality. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

B. Measures

~~7. M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force Operating Plan for backup functionality in accordance with Requirement R1, in electronic or hardcopy format.~~

~~8. M2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have a dated, current, in force copy of its Operating Plan for backup functionality in accordance with Requirement R2, in electronic or hardcopy format, available at its primary control center and at the location providing backup functionality.~~

~~9. M3. Each Reliability Coordinator shall provide dated evidence that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that depend on primary control center functionality in accordance with Requirement R3.~~

~~10. M4. Each Balancing Authority and Transmission Operator shall provide dated evidence that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority or Transmission Operator's primary control center functionality respectively in accordance with Requirement R4.~~

~~11. M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall have evidence that its dated, current, in force Operating Plan for backup functionality, in electronic or hardcopy format, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Requirement R5.~~

~~M2 M1. M6. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have dated evidence that its primary and backup functionality do not~~

~~Standard EOP-008-1—2—~~ Loss of Control Center Functionality

~~depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Requirement R6.~~

~~M3-M1. M7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall provide evidence such as dated records, that it has completed and documented its annual test of its Operating Plan for backup functionality, in accordance with Requirement R7.~~

~~M4.~~ **M8.** ~~M8.~~ Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup functionality will last for more than six calendar months shall provide evidence that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

~~2. Regional Entity.~~

~~1.1. Compliance Monitoring and Enforcement Processes:~~

~~3. Compliance Audits~~

~~4. Self-Certifications~~

~~5. Spot-Checking~~

~~6. Compliance Violation Investigations~~

~~7. Self-Reporting~~

~~8. Complaints~~

~~1.2. Data Retention~~

~~—The Reliability Coordinator, Balancing Authority, and Transmission Operator “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 ~~retain~~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 Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain its dated, current, in ~~force~~effect Operating Plan for backup functionality plus all issuances of the Operating Plan for backup functionality since its last compliance audit in accordance with Measurement M1.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain a dated, current, in ~~force~~effect copy of its Operating Plan for backup functionality, with evidence of its last issue, available at its primary control center and at the location providing backup functionality, for the current year, in accordance with Measurement M2.

~~Standard EOP-008-1—2—~~ Loss of Control Center Functionality

- Each Reliability Coordinator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that it has a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified Reliability Coordinator operators when control has been transferred to the backup facility) in accordance with Requirement R3 that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~ are applicable to the primary control center functionality in accordance with Measurement M3.
- Each Balancing Authority and Transmission Operator shall retain dated evidence for the time period since its last compliance audit, that it has demonstrated that its backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) in accordance with Requirement R4 includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~ are applicable to a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively~~ in accordance with Measurement M4.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall retain evidence for the time period since its last compliance audit, that its dated, current, in ~~force~~ effect Operating Plan for backup functionality, has been reviewed and approved annually and that it has been updated within sixty calendar days of any changes to any part of the Operating Plan described in Requirement R1 in accordance with Measurement M5.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain dated evidence for the current year and for any Operating Plan for backup functionality in ~~force~~ effect since its last compliance audit, that its primary and backup functionality do not depend on each other for the control center functionality required to maintain compliance with Reliability Standards in accordance with Measurement M6.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall retain evidence for the current calendar year and ~~on the~~ previous ~~year~~ calendar years, such as dated records, that it has tested its Operating Plan for backup functionality, in accordance with Measurement M7.
- Each Reliability Coordinator, Balancing Authority, and Transmission Operator that has experienced a loss of their primary or backup functionality and that anticipates that the loss of primary or backup

functionality would last for more than six calendar months shall retain evidence for the current in ~~force~~effect document and any such documents in ~~force~~effect since its last compliance audit that a plan has been submitted to its Regional Entity within six calendar months of the date when the functionality is lost showing how it will re-establish primary or backup functionality in accordance with Measurement M8.

~~8.1.1.3.~~ 1.3. ~~Additional Compliance Information 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.

~~None~~ Violation Severity Levels

R #	~~Violation Severity Levels~~			
R#	Lower ~~VSL~~	Moderate ~~VSL~~	High ~~VSL~~	Severe ~~VSL~~
R1.	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing one of the requirement's six ~~parts~~ (~~Requirement R1~~ , Parts (1.1 through 1.6)).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing two of the requirement's six ~~parts~~ (~~Requirement R1~~ , Parts (1.1 through 1.6)).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing three of the requirement's six ~~parts~~ (~~Requirement R1~~ , Parts (1.1 through 1.6)).	The responsible entity had a current Operating Plan for backup functionality, but the plan was missing four or more of the requirement's six ~~parts~~ (~~Requirement R1~~ , Parts (1.1 through 1.6)) OR The responsible entity did not have a current Operating Plan for backup functionality.
R2.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality available in at least one of its control locations.	N/A	The responsible entity did not have a copy of its current Operating Plan for backup functionality at any of its locations.
R3.	N/A	N/A	N/A	The Reliability Coordinator does not have a backup control center facility (provided through its own dedicated backup facility or at another entity's control center staffed with certified

R #	<u>Violation Severity Levels</u>			
R#	Lower <u>VSL</u>	Moderate <u>VSL</u>	High <u>VSL</u>	Severe <u>VSL</u>
				Reliability Coordinator operators when control has been transferred to the backup facility) that provides the functionality required for maintaining compliance with all Reliability Standards that ~~depend on~~ <u>are applicable to the</u> primary control center functionality.
R4.	N/A	N/A	N/A	~~9.~~ The responsible entity does not have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging,

R #	<u>Violation Severity Levels</u>			
R#	Lower <u>VSL</u>	Moderate <u>VSL</u>	High <u>VSL</u>	Severe <u>VSL</u>
				and alarming sufficient for maintaining compliance with all Reliability Standards that ~~depend on~~ <u>are applicable to</u> a Balancing Authority's and Transmission Operator's primary control center functionality ~~respectively.~~
R5.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 60 calendar days and less than or equal to 70 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 70 calendar days and less than or equal to 80 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not update and approve its Operating Plan for backup functionality for more than 80 calendar days and less than or equal to 90 calendar days after a change to any part of the Operating Plan described in Requirement R1.	The responsible entity did not have evidence that its Operating Plan for backup functionality was annually reviewed and approved. OR, The responsible entity did not update and approve its Operating Plan for backup functionality for more than 90 calendar days after a change to any part of the

R #	<u>Violation Severity Levels</u>			
R#	Lower <u>VSL</u>	Moderate <u>VSL</u>	High <u>VSL</u>	Severe <u>VSL</u>
				Operating Plan described in Requirement R1.
R6.	N/A	N/A	N/A	The responsible entity has primary and backup functionality that do depend on each other for the control center functionality required to maintain compliance with Reliability Standards.
R7.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but it did not document the results. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than two continuous hours but more than or equal to 1.5 continuous hours.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1.5 continuous hours but more than or equal to 1 continuous hour.	The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test did not assess the transition time between the simulated loss of its primary control center and the time to fully implement the backup functionality OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 1 continuous hour but more	The responsible entity did not conduct an annual test of its Operating Plan for backup functionality. OR, The responsible entity conducted an annual test of its Operating Plan for backup functionality, but the test was for less than 0.5 continuous hours.

R #	<u>Violation Severity Levels</u>			
R#	Lower <u>VSL</u>	Moderate <u>VSL</u>	High <u>VSL</u>	Severe <u>VSL</u>
			than or equal to 0.5 continuous hours.	
R8.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months and provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted more than six calendar months but less than or equal to seven calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than seven calendar months but less than or equal to eight calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months provided a plan to its Regional Entity showing how it will re-establish primary or backup functionality but the plan was submitted in more than eight calendar months but less than or equal to nine calendar months after the date when the functionality was lost.	The responsible entity experienced a loss of its primary or backup functionality and anticipated that the loss of primary or backup functionality would last for more than six calendar months, but did not submit a plan to its Regional Entity showing how it will re-establish primary or backup functionality for more than nine calendar months after the date when the functionality was lost.

~~Standard~~ EOP-008-~~1~~-~~2~~ - Loss of Control Center Functionality

~~11.~~

D. ~~E.~~ Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	~~TBD~~ <u>2009 - 2010</u>	~~Revisions for~~ Project 2006-04: <u>Revisions</u>	Major re-write to accommodate changes noted in project file
1	August 5, 2010	<u>Project 2006-04:</u> Adopted by the Board ~~of Trustees~~	
1	April 21, 2011	<u>Project 2006-04:</u> FERC Order issued approving EOP-008-1 (approval effective June 27, 2011)	
1	July 1, 2013	<u>Project 2006-04:</u> Updated VRFs and VSLs based on June 24, 2013 approval.	
<u>2</u>	<u>July 9, 2017</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Revised</u>
<u>2</u>	<u>January 18, 2018</u>	<u>FERC order issued approving EOP-008-2. Docket No. RM17-12-000.</u>	

Supplemental Material

Rationale

Rationale for Requirement R1: The phrase "data exchange capabilities" is replacing "data communications" in Requirement R1, Part 1.2.2 for the following reasons:

COM-001-1 (no longer enforceable) covered telecommunications, which could be viewed as covering both voice and data. COM-001-2.1 (currently enforceable) focuses on "Interpersonal Communication" and does not address data.

The topic of data exchange has historically been covered in the IRO / TOP Standards. Most recently the revisions to the standards that came out of Project 2014-03 Revisions to TOP and IRO Standards use the phrase "data exchange capabilities." The rationale included in the IRO-002-4 standard discusses the need to retain the topic of data exchange, as it is not addressed in the COM standards.

~~WECC Standard FAC-501-WECC-1—Transmission Maintenance~~

A. Introduction

1. **Title:** Transmission Maintenance
2. **Number:** FAC-501-WECC-~~12~~
3. **Purpose:** To ensure the Transmission Owner of a transmission path identified in ~~the table titled “Attachment B, Major WECC Transfer Paths in the Bulk Electric System”~~, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP); and performs and documents maintenance and inspection activities in accordance with the TMIP.

4. Applicability

- ~~4.1~~ Transmission Owners that maintain the transmission paths in ~~the most current table titled “Attachment B, Major WECC Transfer Paths in the Bulk Electric System”~~ provided at:

~~<http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf>~~

5. ***Effective Date:** ~~On the~~The first day of the first quarter, ~~after following~~ applicable regulatory approval.

B. Requirements and Measures

~~R1.~~ R1. Each Transmission ~~Owners~~Owner shall have a TMIP ~~detailing their inspection and maintenance requirements that apply to all transmission facilities necessary for System Operating Limits associated with~~includes, at a minimum, each of the transmission paths identified in table titled “Major WECC Transfer Paths in the Bulk Electric System.”~~items listed in Attachment A, Transmission Maintenance and Inspection Plan Content.~~ [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

~~R1.1.~~ M1. Each Transmission ~~Owners~~Owner will have evidence that it has a TMIP detailing each of the items listed in Attachment A, as required in Requirement R1.

R2. Each Transmission Owners shall annually ~~review their TMIP and update as required.~~its TMIP to reflect all changes to its TMIP. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

~~Transmission Owners shall include the maintenance categories in Attachment 1 FAC-501-WECC-1 when developing their TMIP.~~

M2. Each Transmission Owner will have evidence that it annually updated its TMIP, as required in Requirement R2. When an annual update shows that no changes are required to the TMIP, evidence may include but is not limited to, attestation that the update was performed but showed that no changes were required.

R3. Each Transmission Owner shall adhere to its TMIP. [Violation Risk Factor:

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

~~WECC Standard FAC-501-WECC-1—Transmission Maintenance (Page 5 of 5)~~

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Medium] [Time Horizon: Operations Assessment]

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

~~G.~~ Measures

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

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

~~M3.~~ Each

~~M2.~~ Transmission ~~Owners shall~~Owner will have evidence that ~~their TMIP addresses the required maintenance details of R.2.~~M3. Transmission Owners shall have records that they implemented and followed their it adhered to its TMIP, as required in R.3. ~~The records shall~~Requirement R3. Evidence may include, but is not limited to:

- ~~1.~~ The person or crew responsible for performing the work or inspection,
 - 1.1 The date(s) the ~~work or~~patrol, inspection or maintenance was performed;_i
 - 1.2 The transmission ~~facility~~Facility or Element on which the ~~work~~maintenance was performed,~~and;~~
 - 1.3 A description of the inspection results or maintenance performed.

~~D.C.~~ Compliance

1. Compliance Monitoring Process

~~a. Compliance Monitoring Responsibility~~
~~The British Columbia Utilities Commission~~

~~b. Compliance Monitoring Period~~

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

- ~~1. Self-certification conducted annually~~
- ~~2. Spot check audits conducted anytime with 30 days notice given to prepare~~
- ~~3. Periodic audit as scheduled by the Compliance Enforcement Authority~~
- ~~4. Investigations~~
- ~~5. Other methods as provided for in the Compliance Monitoring Enforcement~~

~~Program The Reset Time Frame shall be one year.~~

~~c. Data Retention~~

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

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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 Transmission Owners listed in section 4.1 shall keep data or evidence for Measure M1 through M3 of Requirements 1-3 for three calendar years ~~plus the current year~~, or since the last audit, whichever is longer.

~~d.~~ **Additional Compliance Information**

~~No additional compliance information.~~

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

~~1.2. Lower:~~ There shall be a Lower Level of non-compliance if any of the following conditions exist:

~~The TMIP does not include associated~~

- ~~• **Facilities** for one of the Paths identified in Attachment 1 FAC 501 WECC 1 as required by R.1 but Transmission Owners are performing maintenance and inspection for the missing Facilities.~~
- ~~• Transmission Owners did not review their TMIP annually as required by R.1.1.~~
- ~~• The TMIP does not include one maintenance category identified in Attachment 1 FAC 501 WECC 1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.~~

~~WECC Standard FAC 501 WECC 1 Transmission Maintenance~~

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

~~1.3. Moderate:~~ There shall be a Moderate Level of non-compliance if any of the following conditions exist:

- ~~• The TMIP does not include associated Facilities for two of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.~~
- ~~• The TMIP does not include two maintenance categories identified in Attachment 1 FAC 501 WECC 1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.~~
- ~~• Transmission Owners are not performing maintenance and inspection for one maintenance category identified in Attachment 1 FAC 501 WECC 1 as required in R3.~~

~~1.4. High:~~ There shall be a High Level of non-compliance if any of the following condition exists:

- ~~• The TMIP does not include associated Facilities for three of the Paths identified in the most current Table titled "Major WECC Transfer Paths in the Bulk Electric System" as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.~~
- ~~• The TMIP does not include three maintenance categories identified in Attachment 1 FAC 501 WECC 1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.~~
- ~~• Transmission Owners are not performing maintenance and inspection for two~~

~~maintenance categories identified in Attachment 1 FAC 501-WECC-1 as required in R3.~~

~~1.5. Severe: There shall be a Severe Level of non-compliance if any of the following condition exists:~~

- ~~• The TMIP does not include associated Facilities for more than three of the Paths identified in the most current Table titled “Major WECC Transfer Paths in the Bulk Electric System” as required by R.1 and Transmission Owners are not performing maintenance and inspection for the missing Facilities.~~
- ~~• The TMIP does not exist or does not include more than three maintenance categories identified in Attachment 1 FAC 501-WECC-1 as required by R.2 but Transmission Owners are performing maintenance and inspection for the missing maintenance categories.~~
- ~~• Transmission Owners are not performing maintenance and inspection for more than two maintenance categories identified in Attachment 1 FAC 501-WECC-1 as required in R3.~~
- ~~•~~

~~WECC Standard FAC 501-WECC-1—Transmission Maintenance~~

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

~~Version on R E~~	~~Violation Severity Levels~~			
	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1.~~	~~The Transmission Owner’s TMIP did not include one of the items listed in Attachment A, as required in Requirement R1.~~	~~The Transmission Owner’s TMIP did not include two of the items listed in Attachment A, as required in Requirement R1.~~	~~The Transmission Owner’s TMIP did not include three of the items listed in Attachment A, as required in Requirement R1.~~	~~The Transmission Owner’s TMIP did not include four or more of the items listed in Attachment A, as required in Requirement R1.~~
~~R2.~~	~~The Transmission Owner did not annually update its TMIP (within the 365 days following the last review), as required by R2.~~	~~The Transmission Owner did not update its TMIP within the last one year and 1 day (within the 366 days following the last review), as required by R2.~~	~~The Transmission Owner did not update its TMIP within the last two years and 1 day (within the 731 days following the last review), as required by R2.~~	~~The Transmission Owner did not update its TMIP within the last three years and 1 day (within the 1095 days following the last review), as required by R2.~~

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

~~WECC Standard FAC 501-WECC-1—Transmission Maintenance (Page 5 of 5)~~

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R3.	<u>†The Transmission Owner failed to adhere to: 1) one transmission line maintenance item, or 2) one station maintenance item, as contained in its TMIP, as required in R3.</u>	<u>April 16, 2008The Transmission Owner failed to adhere to: 1) two transmission line maintenance items; or, 2) two station maintenance items; or 3) any combination of two items taken from the above list, for items contained in its TMIP, as required in R3.</u>	<u>Permanent Replacement Standard for PRC-STD-005-†The Transmission Owner failed to adhere to: 1) three transmission line maintenance items; or, 2) three station maintenance items; or 3) any combination of three items taken from the above list, for items contained in its TMIP, as required in R3.</u>	<u>The Transmission Owner failed to adhere to: 1) four or more transmission line maintenance items; or, 2) four or more station maintenance items; or, 3) any combination of four or more items taken from the above list, for items contained in its TMIP, as required in R3.</u>
<u>†</u>	<u>April 21, 2011</u>	<u>FERC Order issued approving FAC-501-WECC-1 (approval effective June 27, 2011)</u>		

D. Regional Variances**None.****E. Associated Documents**None**Version History – Shows Approval History and Summary of Changes in the Action Field**~~WECC Standard FAC-501-WECC-1~~

<u>Version</u>	<u>Date</u>	<u>Action</u>	<u>Change Tracking</u>
<u>1</u>	<u>April 16, 2008</u>	<u>Permanent Replacement Standard for PRC-STD-005-1</u>	
<u>1</u>	<u>October 29, 2008</u>	<u>NERC BOT conditional approval</u>	
<u>1</u>	<u>April 21, 2011</u>	<u>FERC Approved in Order 751</u>	

<u>2</u>	<u>July 1, 2017</u>	<u>Approved by the WECC Board of Directors.</u>	<u>1) Conformed to newest NERC template and drafting conventions, 2) eliminated URLs, 3) clarified Attachment A, and Measure M3.</u>
<u>2</u>	<u>February 8, 2018</u>	<u>Adopted by the NERC Board of Trustees.</u>	
<u>2</u>	<u>May 30, 2018</u>	<u>FERC Order issued approving FAC-501-WECC-2. Docket No. RD18-5-000</u>	

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

~~WECC Standard FAC 501 WECC 1—Transmission Maintenance (Page 5 of 5)~~

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Attachment A
Transmission Maintenance and Inspection Plan Content

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

The maintenance practices in the TMIP may be performance based, time based, conditional based, or a combination of all three. The TMIP shall include, at a minimum, each of the following details:

1. Facilities

A list of Facilities ~~and associated (e.g., transmission lines, transformers, etc.) and~~ Elements ~~necessary to maintain the SOL for the transfer paths (e.g. circuit breaker, bus section, etc.) that comprise each transmission path(s) identified in the most current Table titled “Attachment B, Major WECC Transfer Paths in the Bulk Electric System.”~~

~~1. The scheduled interval for any time-based maintenance activities and/or a description supporting condition or performance-based maintenance activities including a description of the condition-based trigger;~~

2. Maintenance Methodology

A description of the maintenance methodology used for the Facility, transmission line, or station included in the TMIP.

The TMIP maintenance methodology may be any one of the following or any combination thereof, but must include at least one of the following:

- Performance-based
- Time-based
- Condition based

3. Periodicity

A specification of the periodicity that the described maintenance will occur, or under what circumstances it occurs.

5.4. Transmission Line Maintenance Details:

A description of each of the following for the transmission line(s) included in the TMIP:

- a. Inspection requirements
- a-b. Patrol/Inspection requirements
- a. ~~Contamination Control~~
- b-c. Tower and wood pole structure management

6.5. Station Maintenance Details:

- b. ~~Inspections~~

~~e. Contamination Control~~
A description of each of

~~Equipment Maintenance~~ for the following for each station included in the TMIP:

a. Inspection requirements

b. Equipment maintenance for each of the following:

1. Circuit ~~Breakers~~breakers
2. Power ~~Transformer~~transformers (including, but not limited to,
phase-shifting transformers)
- ~~Regulators~~
3. Reactive Devicesdevices (including, but not limited to, ~~Shunt Capacitors,~~
~~Series Capacitors, Synchronous Condensers, Shunt Reactors~~shunt
capacitors, series capacitors, synchronous condensers, shunt reactors, and
tertiary reactors)

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

~~WECC Standard FAC 501-WECC 1-Transmission Maintenance (Page 5 of 5)~~

Attachment B**Major WECC Transfer Paths in the Bulk Electric System** ~~Tertiary Reactors)~~

	<u>PATH NAME*</u>	<u>Path Number</u>
1.	<u>Alberta – British Columbia</u>	<u>1</u>
2.	<u>Northwest – British Columbia</u>	<u>3</u>
3.	<u>West of Cascades – North</u>	<u>4</u>
4.	<u>West of Cascades – South</u>	<u>5</u>
5.	<u>West of Hawaii</u>	<u>6</u>
6.	<u>Montana to Northwest</u>	<u>8</u>
7.	<u>Idaho to Northwest</u>	<u>14</u>
8.	<u>South of Los Banos or Midway- Los Banos</u>	<u>15</u>
9.	<u>Idaho – Sierra</u>	<u>16</u>
10.	<u>Borah West</u>	<u>17</u>
11.	<u>Idaho – Montana</u>	<u>18</u>
12.	<u>Bridger West</u>	<u>19</u>
13.	<u>Path C</u>	<u>20</u>
14.	<u>Southwest of Four Corners</u>	<u>22</u>
15.	<u>PG&E – SPP</u>	<u>24</u>
16.	<u>Northern – Southern California</u>	<u>26</u>
17.	<u>Intmntn. Power Project DC Line</u>	<u>27</u>
18.	<u>TOT 1A</u>	<u>30</u>
19.	<u>TOT 2A</u>	<u>31</u>
20.	<u>Pavant – Gonder 230 kV</u> <u>Intermountain – Gonder 230 kV</u>	<u>32</u>
21.	<u>TOT 2B</u>	<u>34</u>
22.	<u>TOT 2C</u>	<u>35</u>
23.	<u>TOT 3</u>	<u>36</u>
24.	<u>TOT 5</u>	<u>39</u>
25.	<u>SDGE – CFE</u>	<u>45</u>
26.	<u>West of Colorado River (WOR)</u>	<u>46</u>
27.	<u>Southern New Mexico (NM1)</u>	<u>47</u>
28.	<u>Northern New Mexico (NM2)</u>	<u>48</u>
29.	<u>East of the Colorado River (EOR)</u>	<u>49</u>
30.	<u>Cholla – Pinnacle Peak</u>	<u>50</u>
31.	<u>Southern Navajo</u>	<u>51</u>
32.	<u>Brownlee East</u>	<u>55</u>
33.	<u>Lugo – Victorville 500 kV</u>	<u>61</u>
34.	<u>Pacific DC Intertie</u>	<u>65</u>
35.	<u>COI</u>	<u>66</u>
36.	<u>North of John Day cutplane</u>	<u>73</u>
37.	<u>Alturas</u>	<u>76</u>
38.	<u>Montana Southeast</u>	<u>80</u>
39.	<u>SCIT**</u>	
40.	<u>COI/PDCI – North of John Day cutplane**</u>	

* For an explanation of terms, path numbers, and definition for the paths refer to WECC's Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC's Path Rating Catalog.

THIS SECTION WILL NOT BE PART OF THE STANDARD BUT IS REQUIRED FOR NERC FILING.

Standards Authorization Request (SAR)

WECC-0120 FAC-501-WECC-2 Transmission Maintenance SAR

Approvals Required

• <u>WECC Ballot Pool</u>	<u>Pending</u>
• <u>WECC Board of Directors</u>	<u>Pending</u>
• <u>NERC Board of Trustees</u>	<u>Pending</u>
• <u>FERC</u>	<u>Pending</u>

Applicable Entities

Transmission Owners that maintain the transmission paths in the most current WECC Major Paths table (Attachment B of the standard)

Conforming Changes to Other Standards

None are required.

Proposed Effective Date

The first day of the first quarter following regulatory approval

Justification

The WECC-0120, FAC-501-WECC-2, Transmission Maintenance Drafting Team (DT) has reviewed NERC Standards, both in effect and those standards that are NERC Board of Trustees approved pending regulatory filing. The DT concluded that the proposed substantive changes pose a minimal burden beyond ordinary and current operations. As such, the short implementation time should impose no undue burden.

Consideration of Early Compliance

The DT foresees no negative impacts to reliability in the event of early compliance.

Retirements

None

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

~~WECC Standard FAC-501-WECC-1—Transmission Maintenance (Page 5 of 5)~~

A. Introduction

1. Title: Operating Personnel Credentials
2. Number: PER-003-~~12~~
3. Purpose:- To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Real-time operating position responsible for control of the Bulk Electric System.
4. Applicability:

4.1. Functional Entities:

- 4.1.1. Reliability Coordinator
- 4.1.2. Transmission Operator
- 4.1.3. Balancing Authority

~~1. Effective Date*:~~

5. ~~In those jurisdictions where regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective the first calendar day of the first calendar quarter twelve months after Board of Trustees adoption~~ See Implementation Plan for PER-003-2.

B. Requirements and Measures

- R1. Each Reliability Coordinator shall staff its Real-time operating positions performing Reliability Coordinator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certificate ⁽⁺⁾ (1)(2). [Risk Factor: High][Time Horizon: Real-time Operations]
 - 1.1. Areas of Competency
 - 1.1.1. Resource and demand balancing
 - 1.1.2. Transmission operations
 - 1.1.3. Emergency preparedness and operations
 - 1.1.4. System operations
 - 1.1.5. Protection and control

¹ Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

² The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

PER-003-2 – Operating Personnel Credentials

1.1.6. Voltage and reactive

1.1.7. Interchange scheduling and coordination

1.1.8. Interconnection reliability operations and coordination

M1.

~~¹ Non-NERC certified personnel performing any reliability related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.~~

~~* Mandatory BC Effective Date: January 1, 2015~~

¹ [Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.](#)

² [The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.](#)

Each Reliability Coordinator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

M1.1 A list of Real-time operating positions.

M1.2 A list of System Operators assigned to its Real-time operating positions.

M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R2. Each Transmission Operator shall staff its Real-time operating positions performing Transmission Operator reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates ~~(1)(2)~~⁽¹⁾⁽²⁾. *[Risk Factor: High][Time Horizon: Real-time Operations]:*

2.1. Areas of Competency

- 2.1.1.** Transmission operations
- 2.1.2.** Emergency preparedness and operations
- 2.1.3.** System operations
- 2.1.4.** Protection and control
- 2.1.5.** Voltage and reactive

2.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Transmission Operator

M2. Each Transmission Operator shall have the following evidence to show that it staffed its Real-time operating positions performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate:

¹ Non-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

² The NERC certificates referenced in this standard pertain to those certificates identified in the NERC System Operator Certification Program Manual.

M2.1 A list of Real-time operating positions.

M2.2 A list of System Operators assigned to its Real-time operating positions.

M2.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M2.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

R3. Each Balancing Authority shall staff its Real-time operating positions performing Balancing Authority reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining one of the following valid NERC certificates ⁽⁺⁾~~(1)~~₍₂₎. [Risk Factor: High][Time Horizon: Real-time Operations]:

3.1. Areas of Competency

- 3.1.1.** Resources and demand balancing
- 3.1.2.** Emergency preparedness and operations
- 3.1.3.** System operations
- 3.1.4.** Interchange scheduling and coordination

3.2. Certificates

- Reliability Operator
- Balancing, Interchange and Transmission Operator
- Balancing and Interchange Operator

~~C. Measures~~

M3. Each~~M1. Each Reliability Coordinator, Transmission Operator and~~ Balancing Authority shall have the following evidence to show that it staffed its Real-time operating positions

[†]Non-NERC certified personnel performing any reliability-related task of an operating position must be under the direct supervision of a NERC-Certified System Operator stationed at that operating position; the NERC-Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks.

performing reliability-related tasks with System Operators who have demonstrated the applicable minimum competency by obtaining and maintaining the appropriate, valid NERC certificate ~~(R1, R2, R3)~~;

M3.1 A list of Real-time operating positions.

M3.2 A list of System Operators assigned to its Real-time operating positions.

M3.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.

M3.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real-time operating positions.

~~M1.1 A list of Real time operating positions.~~

~~M1.2 A list of System Operators assigned to its Real time operating positions.~~

~~M1.3 A copy of each of its System Operator's NERC certificate or NERC certificate number with expiration date which demonstrates compliance with the applicable Areas of Competency.~~

~~M1.4 Work schedules, work logs, or other equivalent evidence showing which System Operators were assigned to work in Real time operating positions.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring~~Enforcement Authority:

~~The British Columbia Utilities Commission~~

~~1.1. Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audits Self~~

~~Certifications Spot~~

~~Checking~~

~~Compliance Violation Investigations Self-Reporting~~

~~Complaints~~

~~1.2. Data Retention~~

~~Each Reliability Coordinator, Transmission Operator and Balancing 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 ~~for three years or since its last compliance audit, whichever time frame is the greatest,~~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.

- ~~If a~~Each Reliability Coordinator, Transmission Operator ~~or~~and Balancing Authority ~~is found non-compliant, it shall keep information related to the non-~~data or evidence for three years or since its last compliance ~~until found compliant or the time period specified above~~audit, whichever time frame is ~~longer~~the greatest.

~~1.2.1.3. The Compliance Monitoring and Enforcement Authority shall keep the last audit records and all requested and submitted subsequent records.~~Program

~~1.3. Additional Compliance Information~~

~~None.~~

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.

PER-003-2.0 – Operating Personnel Credentials**Violation Severity Levels**

R#	Lower-VSL	Medium-VSL	High-VSL	Severe-VSL
~~R1~~				~~The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.~~
~~R2~~				~~The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.~~
~~R3~~				~~The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.~~

<u>R #</u>	<u>Violation Severity Levels</u>			
	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>R1.</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The Reliability Coordinator failed to staff each Real-time operating position performing Reliability Coordinator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R1.</u>

<u>R2.</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The Transmission Operator failed to staff each Real-time operating position performing Transmission Operator reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R2, Part 2.2.</u>
<u>R3.</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>The Balancing Authority failed to staff each Real-time operating position performing Balancing Authority reliability-related tasks with a System Operator having a valid NERC certificate as defined in Requirement R3, Part 3.2.</u>

PER-003-2 – Operating Personnel Credentials

D. Regional Variances

None.

E. Associated Documents-

Implementation Plan

Version History

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~+~~	~~February 17, 2011~~	~~Complete revision under Project 2007-04~~	~~Revision~~
~~+~~	~~February 17, 2011~~	~~Adopted by Board of Trustees~~	
~~+~~	~~September 15, 2011~~	~~FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)~~	

<u>Version</u>	<u>Date</u>	<u>Action</u>	<u>Change Tracking</u>
<u>0</u>	<u>April 1, 2005</u>	<u>Effective Date</u>	<u>New</u>
<u>1</u>	<u>February 17, 2011</u>	<u>Complete revision under Project 2007-04</u>	<u>Revision</u>
<u>1</u>	<u>February 17, 2011</u>	<u>Adopted by Board of Trustees</u>	
<u>1</u>	<u>September 15, 2011</u>	<u>FERC Order issued by FERC approving PER-003-1 (effective date of the Order is September 15, 2011)</u>	
<u>2</u>	<u>May 10, 2018</u>	<u>Added footnote to requirements</u>	<u>Revision</u>
<u>2</u>	<u>May 10, 2018</u>	<u>Adopted by Board of Trustees</u>	<u>Revision</u>
<u>2</u>	<u>November 21, 2018</u>	<u>FERC Letter Order approving PER-003-2. Docket No. RD18-9-000</u>	

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

The standard drafting team (PRC 025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

<u>Completed Actions</u>	<u>Date</u>
<u>The Standards Committee (SC) authorized the SAR for posting</u>	<u>September 14, 2016</u>
<u>Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period</u>	<u>September 16, 2016 through October 18, 2016</u>
<u>Draft 2 of the SAR was posted for a 15-day informal comment period</u>	<u>March 20, 2017 through April 3, 2017</u>
<u>The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)</u>	<u>April 19, 2017</u>
<u>Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period</u>	<u>July 25, 2017 through September 9, 2017</u>
<u>Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period</u>	<u>October 30, 2017 through December 14, 2017</u>

<u>Anticipated Actions</u>	<u>Date</u>
<u>45-day formal comment period with initial ballot</u>	<u>July 2017</u>
<u>45-day formal comment period with additional ballot</u>	<u>October 2017</u>
<u>10-day final ballot</u>	<u>January 2018</u>
<u>Board adoption</u>	<u>February 2018</u>

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.

PRC-025-~~12~~— Generator Relay Loadability

A. Introduction

1. **Title:** Generator Relay Loadability
2. **Number:** PRC-025-~~12~~
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Generator Owner that applies load-responsive protective relays¹ at the terminals of the Elements listed in ~~34.2~~, Facilities.
 - 4.1.2. Transmission Owner that applies load-responsive protective ~~relays~~relays¹ at the terminals of the Elements listed in ~~34.2~~, Facilities.
 - 4.1.3. Distribution Provider that applies load-responsive protective ~~relays~~relays¹ at the terminals of the Elements listed in ~~34.2~~, Facilities.
 - 4.2. **Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:
 - 4.2.1. Generating unit(s).
 - 4.2.2. Generator step-up (i.e., GSU) transformer(s).
 - 4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.²
 - 4.2.4. 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; except that Elements may also supply generating plant loads.
 - 4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. Effective Date: See Implementation Plan

¹ Relays include low voltage protection devices that have adjustable settings.

² These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~12~~ Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

PRC-025-12— Generator Relay Loadability

5.6. Background: After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.³

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

~~6.1. Effective Date:~~ See Implementation Plan

B. Requirements and Measures

- R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-12 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*
- M1.** For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-12 – Attachment 1: Relay Settings.

C. Compliance**1. Compliance Monitoring Process****6.1. Compliance Enforcement Authority**

- 1.1.** ~~As defined in the NERC Rules of Procedure;~~ “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise

³ ~~Interim Report~~ Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

PRC-025-12— Generator Relay Loadability

designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the NERC mandatory and enforceable Reliability Standards in their respective jurisdictions.

- 1.2. Evidence Retention:** The following evidence retention periods~~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 (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, Transmission Owner, and Distribution Provider~~applicable entity~~ shall keep data or evidence to show compliance as identified below unless directed by its CEA~~Compliance Enforcement Authority~~ to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

6.2. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot-Checking

Compliance Investigation

Self-Reporting

Complaint

6.3. Additional Compliance Information

None

PRC-025-~~12~~— Generator Relay Loadability

~~Table of Compliance Elements~~

PRC-025-12— Generator Relay Loadability

Violation Severity Levels

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 Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with PRC-025-12 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

Deleted Cells

Deleted Cells

PRC-025-~~12~~— Generator Relay Loadability

D. Regional Variances

None.

~~E.~~ Interpretations

~~None.~~

~~F.~~ E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, “~~[“Considerations for Power Plant and Transmission System Protection Coordination.”](#)~~” technical reference document, Revision 2. (Date of Publication: July 2015)~~

[NERC System Protection and Control Subcommittee, “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition.” \(Date of Publication: March 2016\)](#)

IEEE C37.102-2006, [“IEEE Guide for AC Generator Protection.” \(Date of Publication: 2006\)](#)

[IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage \(1000 V and below\) AC and General Purpose \(1500 V and below\) DC Power Circuit Breakers.” \(Date of Publication: September 18, 2012\)](#)

[IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” \(Date of Publication: October 3, 2008\)](#)

PRC-025-~~12~~— Generator Relay Loadability

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
<u>2</u>	<u>April 19, 2017</u>	<u>Standards Committee acceptance of the Standards Authorization Request</u>	<u>Project 2016-04</u>
<u>2</u>	<u>TBD</u>	<u>Adopted by NERC Board of Trustees</u>	<u>Revised</u>
<u>2</u>	<u>TBD</u>	<u>FERC order issued approving PRC-025-2</u>	

PRC-025-~~12~~— Generator Relay Loadability**PRC-025-2 – Attachment 1: Relay Settings****Introduction**

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in ~~34.2~~, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads ~~to~~), the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

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result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective 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).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~ Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~full load~~ full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.⁴
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

⁴ IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

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The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, 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).~~ Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive [distance or overcurrent](#) protective relay [by IEEE device numbers](#) (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. [This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous \(e.g., L, S, and I\).](#) A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, [except when the same application continues on the next page of the table with a different relay type.](#)

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

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Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
Synchronous generating unit(s), ~~or~~ including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
The same application continues on the next page with a different relay type				

⁵ Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~ energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

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Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria	
Synchronous generating unit(s), ~~including~~ Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51), or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
	2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation		
	The same application continues with a different relay type below				
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage	
A different application starts on the next page					

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~ including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51), or (51V-R) – voltage-restrained	~~55a~~	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	OR			
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				
	Phase distance relay (e.g., 21) – directional toward the Transmission system – ~~installed on generator side~~	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor

Merged Cells

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
<u>Relays installed on generator-side⁶ of the</u> Generator step-up transformer(s) connected to synchronous generators	<u>of the GSU transformer</u> If the relay is installed on the high-side of the GSU transformer use Option 14	OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
<u>Relays installed on generator-side⁷ of the</u> Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (<u>e.g., 50 or 51</u>) – <u>installed on generator-side of the GSU transformer</u>	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

⁶ If the relay is installed on the high-side of the GSU transformer, use Option 14.⁷ If the relay is installed on the high-side of the GSU transformer use, Option 15.

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Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria	
	If the relay is installed on the high-side of the GSU transformer use Option 15	8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
	The same application continues on the next page with a different relay type				
Relays installed on generator-side ⁸ of the Generator step-up transformer(s) connected to synchronous generators	Phase directional time-overcurrent relay (e.g., 67) – directional toward the Transmission system —installed on generator-side	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			

⁸ If the relay is installed on the high-side of the GSU transformer use, Option 16.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
	~~of the GSU transformer~~ If the relay is installed on the high-side of the GSU transformer use Option 16	9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

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Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (~~e.g., 21~~) – directional toward the Transmission system— ~~installed on generator-side of the GSU transformer~~ If the relay is installed on the high-side of the GSU transformer use Option 17 ⁹	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (~~e.g., 50 or 51~~)— ~~installed on generator-side of the GSU transformer~~ If the relay is installed on the high-side of the GSU transformer use Option 18 ¹⁰	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

⁹ If the relay is installed on the high-side of the GSU transformer, use Option 17.¹⁰ If the relay is installed on the high-side of the GSU transformer, use Option 18.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional ~~time~~ -overcurrent relay (e.g., 67) – directional toward the Transmission system—installed on generator side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19 ¹¹	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~ on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		

Merged Cells

¹¹ If the relay is installed on the high-side of the GSU transformer, use Option 19.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
	side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
A different application starts on the next page				
A different application starts on the next page				
<u>Relays installed on the high-side of the GSU transformer,¹² including relays installed on the remote end of line, for</u> 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. <u>(except that</u> Elements may also supply generating plant loads. <u>–)</u> – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system— <u>installed on the high-side of the GSU transformer</u>	14a	0.85 per unit of the line nominal voltage <u>at the relay location</u>	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
	<u>If the relay is installed on the generator side of the GSU transformer use Option 7</u>	14b	Simulated line voltage <u>at the relay location</u> coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit <u>of the line</u> nominal voltage <u>on at the high-side terminals remote end of the generator step-up transformer line</u> prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
		The same application continues on the next page with a different relay type		

¹² If the relay is installed on the generator-side of the GSU transformer, use Option 7.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
<u>Relays installed on the high-side of the GSU transformer,¹³ including relays installed at the remote end of the line, for</u> 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: <u>(except that</u> Elements may also supply generating plant loads: <u>–) –</u> connected to synchronous generators	Phase <u>instantaneous</u> overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications <u>installed on the high-side of the GSU transformer and/or</u> phase time overcurrent relay (e.g., 51) <u>– installed on the high-side of the GSU transformer</u> <u>If the relay is installed on the generator-side of the GSU transformer use Option 8</u>	15a	0.85 per unit of the line nominal voltage <u>at the relay location</u>	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage <u>at the relay location</u> coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit <u>of the line</u> nominal voltage <u>on at the high-side terminalsremote end</u> of the <u>generator step-up transformerline</u> prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

¹³ If the relay is installed on the generator-side of the GSU transformer, use Option 8.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
The same application continues on the next page with a different relay type				
<u>Relays installed on the high-side of the GSU transformer,¹⁴ including relays installed at the remote end of the line, for</u> Elements that connect the GSU transformer(s) to the	Phase directional <u>instantaneous</u> overcurrent supervisory element (<u>e.g., 67</u>) – associated with current-based,	16a	0.85 per unit of the line nominal voltage <u>at the relay location</u>	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

¹⁴ If the relay is installed on the generator-side of the GSU transformer, use Option 9.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant: ~~(except that Elements may also supply generating plant load.)~~ –connected to synchronous generators	communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer and/or~~ phase directional time overcurrent relay ~~(e.g., 67) –~~ directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ If the relay is installed on the generator-side of the GSU transformer use Option 9	16b	Simulated line voltage ~~at the relay location~~ coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~of the line~~ nominal voltage ~~on at the high-side terminals remote end~~ of the ~~generator step-up transformer line~~ prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

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Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
A different application starts on the next page				
<u>Relays installed on the high-side of the GSU transformer,¹⁵ including relays installed on the remote end of line, for</u> 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: <u>(except that</u> Elements may also supply	Phase distance relay (e.g., 21) – directional toward the Transmission system— ~~installed on the high-side of the GSU transformer~~ <u>If the relay is installed on the generator-side of the GSU transformer use Option 10</u>	17	1.0 per unit of the line nominal voltage <u>at the relay location</u>	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

¹⁵ If the relay is installed on the generator-side of the GSU transformer, use Option 10.

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
generating plant loads; —connected to asynchronous generators only (including inverter-based installations)	The same application continues on the next page with a different relay type			

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Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
<u>Relays installed on the high-side of the GSU transformer,¹⁶ including, relays installed on the remote end of the line, for</u> 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: <u>(except that</u> Elements may also supply generating plant loads.) – connected to asynchronous generators only (including inverter-based installations)	Phase <u>instantaneous</u> overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications <u>installed on the high-side of the GSU transformer and/or</u> Phase time overcurrent relay (e.g., 51) – <u>installed on the high-side of the GSU transformer</u> <u>If the relay is installed on the generator-side of the GSU transformer use Option 11</u>	18	1.0 per unit of the line nominal voltage <u>at the relay location</u>	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
The same application continues on the next page with a different relay type				

¹⁶ If the relay is installed on the generator-side of the GSU transformer, use Option 11.

PRC-025-~~12~~— Generator Relay Loadability

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁵	Pickup Setting Criteria
<u>Relays installed on the high-side of the GSU transformer,¹⁷ including relays installed on the remote end of the line, for</u> 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: <u>(except that</u> Elements may also supply generating plant loads.)—connected to asynchronous generators only (including inverter-based installations)	Phase directional <u>instantaneous</u> overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system <u>installed on the high-side of the GSU transformer</u> and/or Phase directional time overcurrent relay (e.g., 67)—<u>installed on the high-side of the GSU transformer</u> <u>If the relay is installed on the generator-side of the GSU transformer use Option 12</u>	19	1.0 per unit of the line nominal voltage <u>at the relay location</u>	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

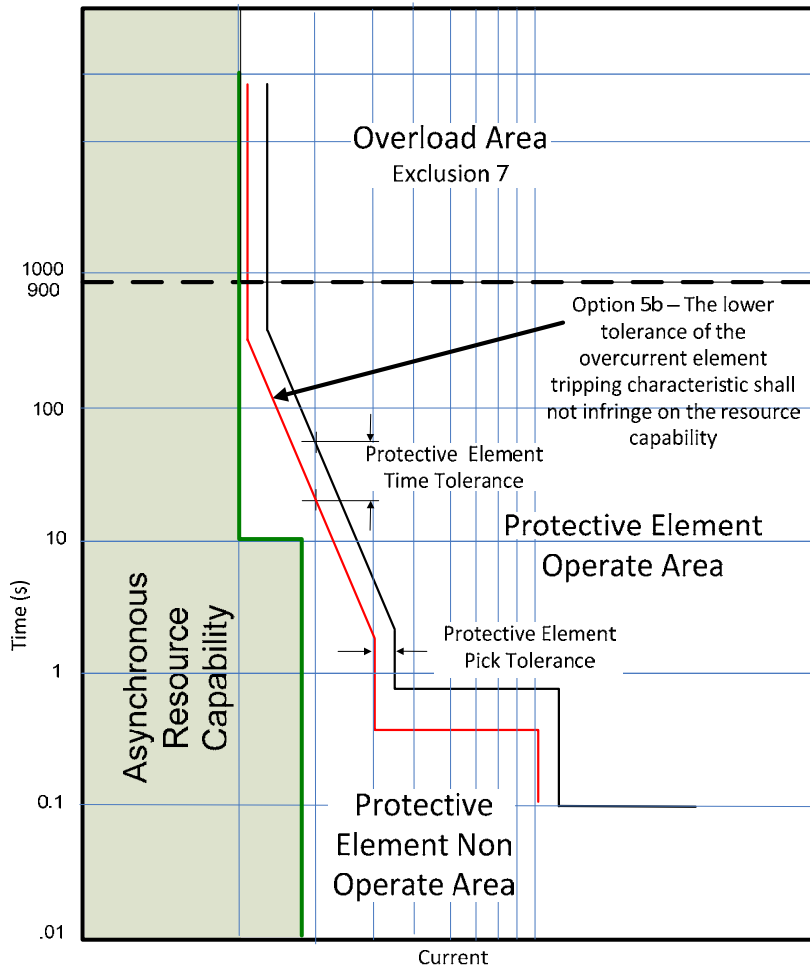
PRC-025-~~12~~— Generator Relay Loadability

Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-12 Guidelines and Technical Basis

Introduction

The document, [“Considerations for Power Plant and Transmission System Protection Coordination”](#) published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2010¹⁸.

The basis for the standard’s loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, “while maintaining reliable fault protection” in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed

¹⁸

<http://www.nerc.com/docs/pe/spctf/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/S PCS%20 Gen%20Prot%20Coord%20Rev1%20Final%202007-30-2010%20Coordination%20Technical%20Reference%20Document.pdf>

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 this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance ~~is~~^{are} dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator

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interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

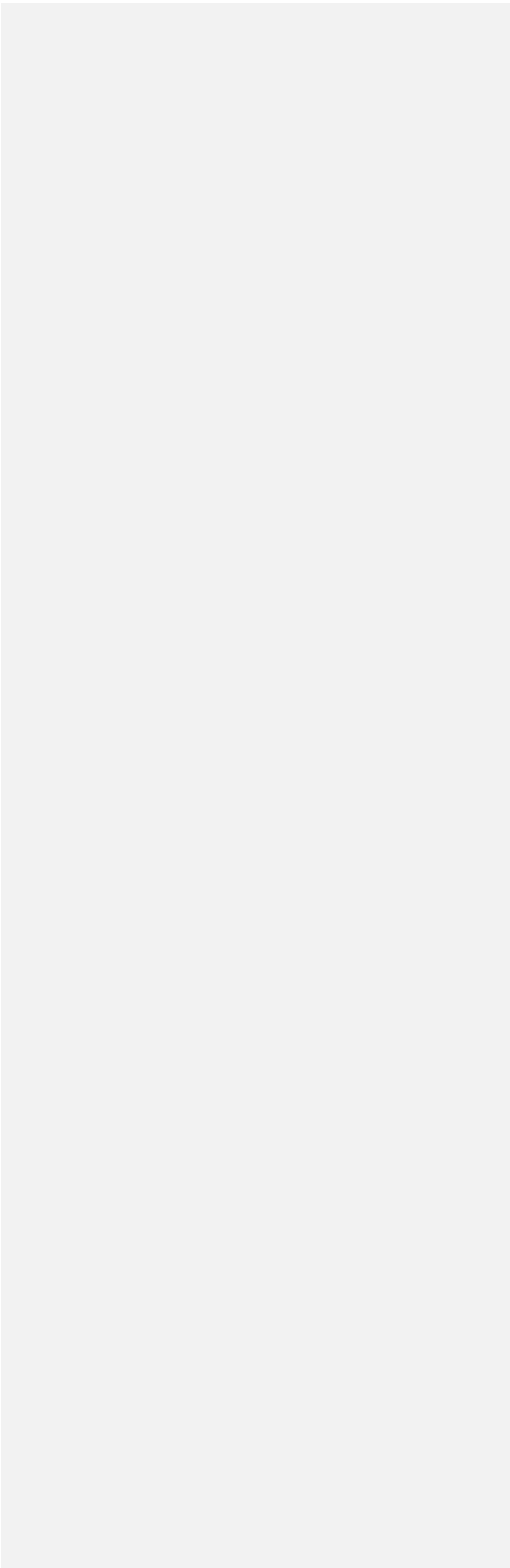
Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-1~~2~~ using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

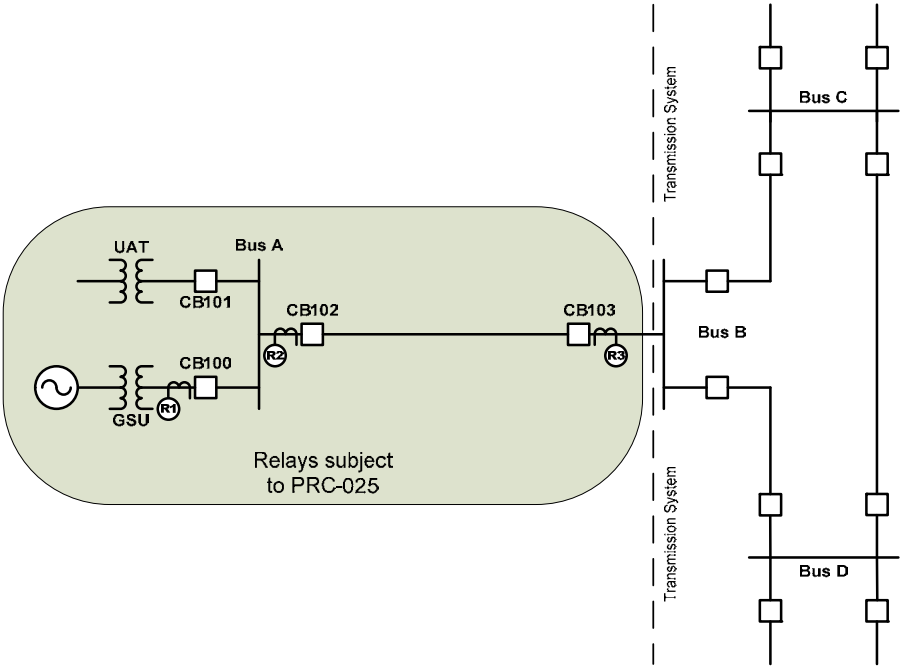
The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-1~~2~~ and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for 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. The backup protective function would apply the requirement in the PRC-025-1~~2~~ standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case,~~

~~Since 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 are applicable responsible entity's to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in this standard or. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased transmission system loading generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 this standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~

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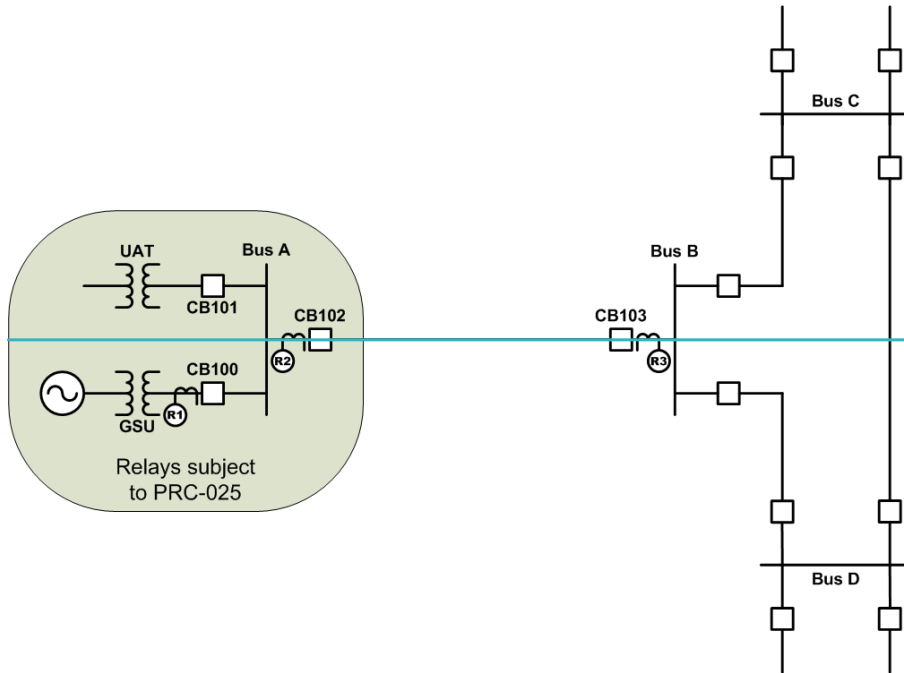


Figure 1: Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-4.2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-4.2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for 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

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differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since 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 are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

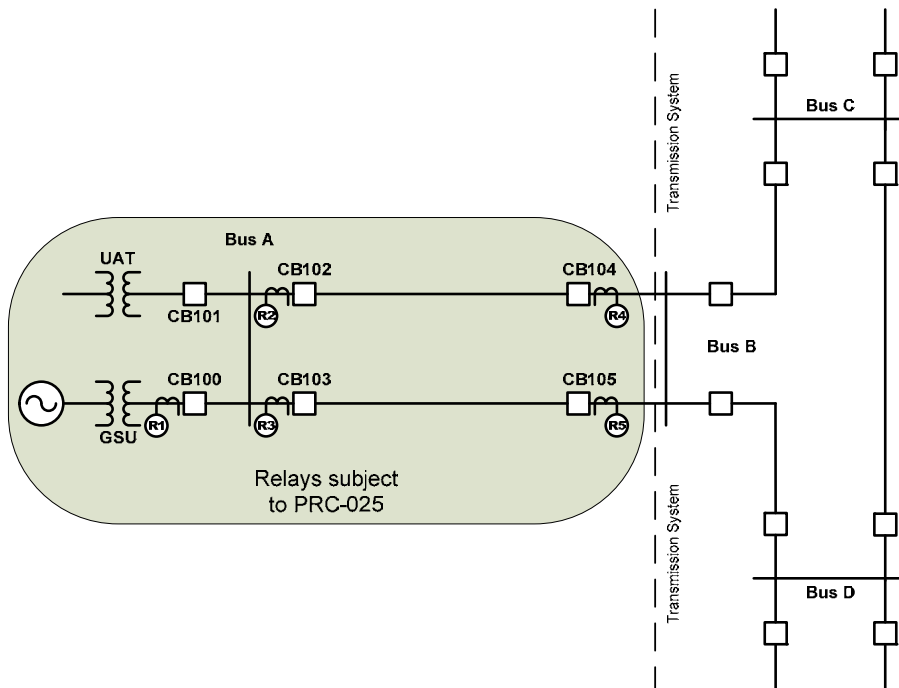


Figure 2: Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~42~~ using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

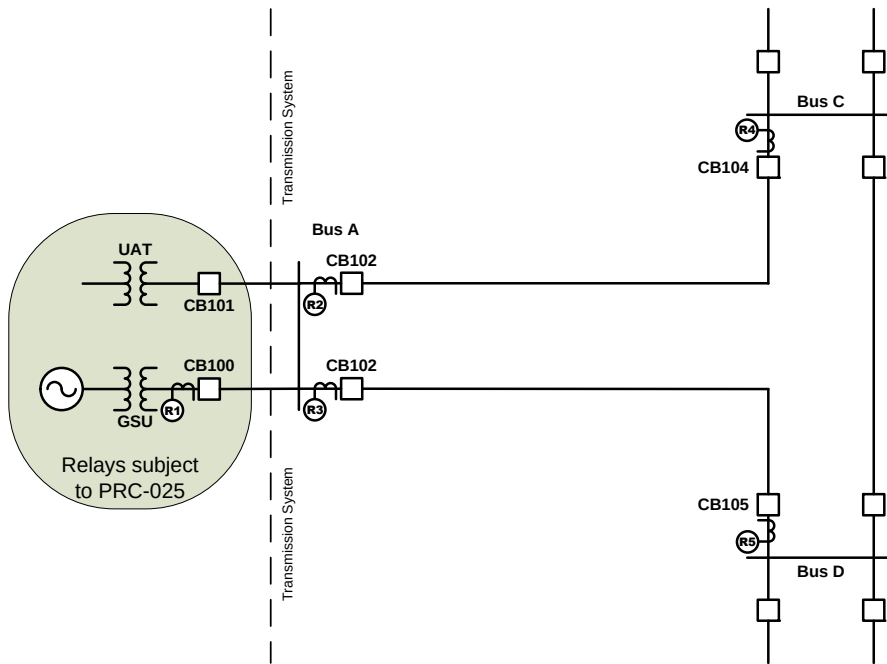


Figure 3: Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. [The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called](#)

Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition,¹⁹ March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system” or “feeders”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

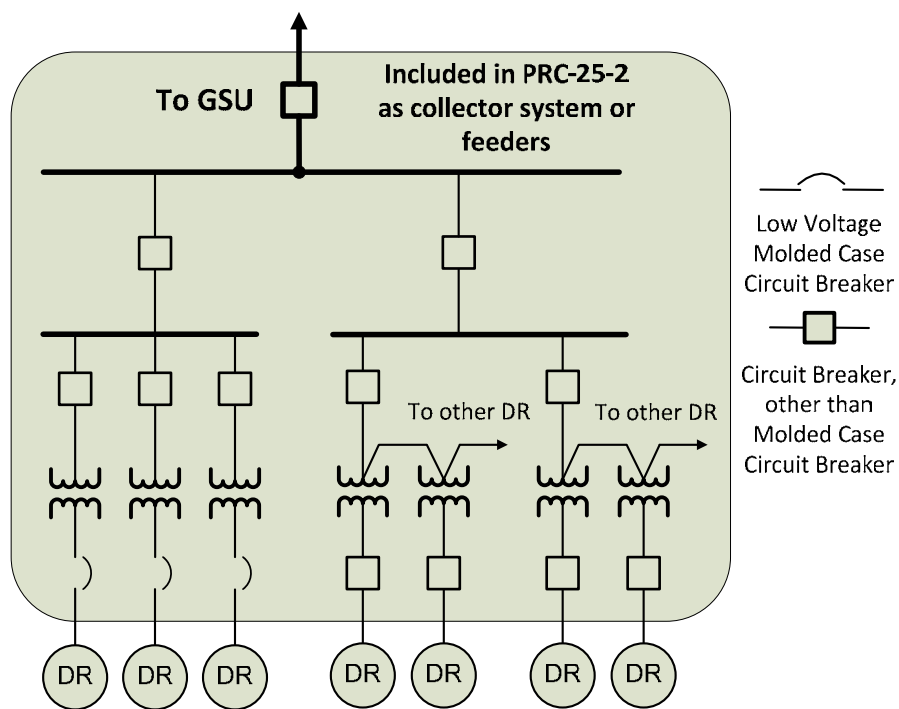


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

¹⁹ [http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB 2016 final.pdf](http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB%202016%20final.pdf).

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as “field-forcing,” results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~^{the line} nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior ~~not~~ occurred.

The dynamic load levels specified in Table 1 under column “~~Pickup~~ Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator

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Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-025.

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 are included in PRC-025-~~42~~. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~42~~. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure ~~56~~) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators, ~~however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use

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the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on at the remote end of the line or at~~ the high-side of the GSU transformer. ~~(as prescribed by the Table 1 criteria).~~ This can be simulated by means such as modeling the connection of a shunt reactor ~~on at the Transmission system to lower remote end of the line or at~~ the GSU transformer high-side ~~to lower the~~ voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage ~~to be used at the relay location~~ to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing which contributed~~ to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, “Guide for AC Generator Protection,” describes the purpose of this protection as follows (emphasis added):

*“The distance relay applied for this function is intended to isolate the generator from the power system for a fault **that is not cleared by the transmission line breakers**. In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored*

at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and **normal loading conditions**. However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers **to optimize coordination while still protecting the turbine generator**. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions. **Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.** With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting.”

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays,

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implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the [Considerations for Power Plant and Transmission System Protection Coordination](#) technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

[Phase Instantaneous Overcurrent Relay \(e.g., 50\)](#)

[The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.](#)

[Phase Time Overcurrent Relay \(e.g., 51\)](#)

See [section 3.9-Chapter 2](#) of the [Considerations for Power Plant and Transmission System Protection Coordination](#) technical reference document for a detailed discussion of this protection function. Note that the [Table 1](#) setting criteria established within the Table 1 options differ from [section 3.9.2 of the Considerations for Power Plant and Transmission System Protection Coordination](#) technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator [operatesis a](#) synchronous or asynchronous [unit](#).

[Phase Time Overcurrent Relay – Voltage-Restrained \(e.g., 51V-R\)](#)

Phase time overcurrent voltage-restrained relays ([e.g., 51V-R](#)), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See [section 3.10Chapter 2](#) of the [Considerations for Power Plant and Transmission System Protection Coordination](#) technical reference document for a detailed discussion of this protection function.

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Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See [section 3.10Chapter 2](#) of the [Considerations for](#) Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See [section 3.9Chapter 2](#) of the [Considerations for](#) Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the [Table 1settingsetting](#) criteria established within the Table 1 options differ from [section 3.9.2](#) of the [Considerations for](#) Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator [operatesis a](#) synchronous or asynchronous [unit](#).

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the [Considerations for Power Plant and Transmission System Protection Coordination](#) technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures [45](#) and [56](#) below illustrate the connections for each of the Table 1 options provided in PRC-025-~~42~~, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

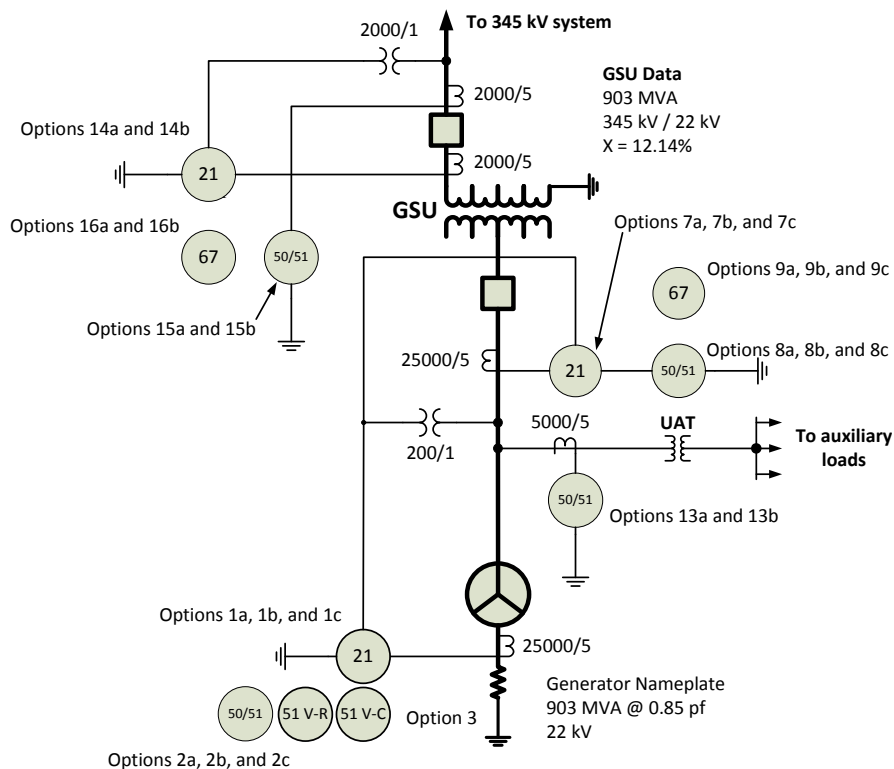


Figure 4.5: Relay Connection for corresponding synchronous options.

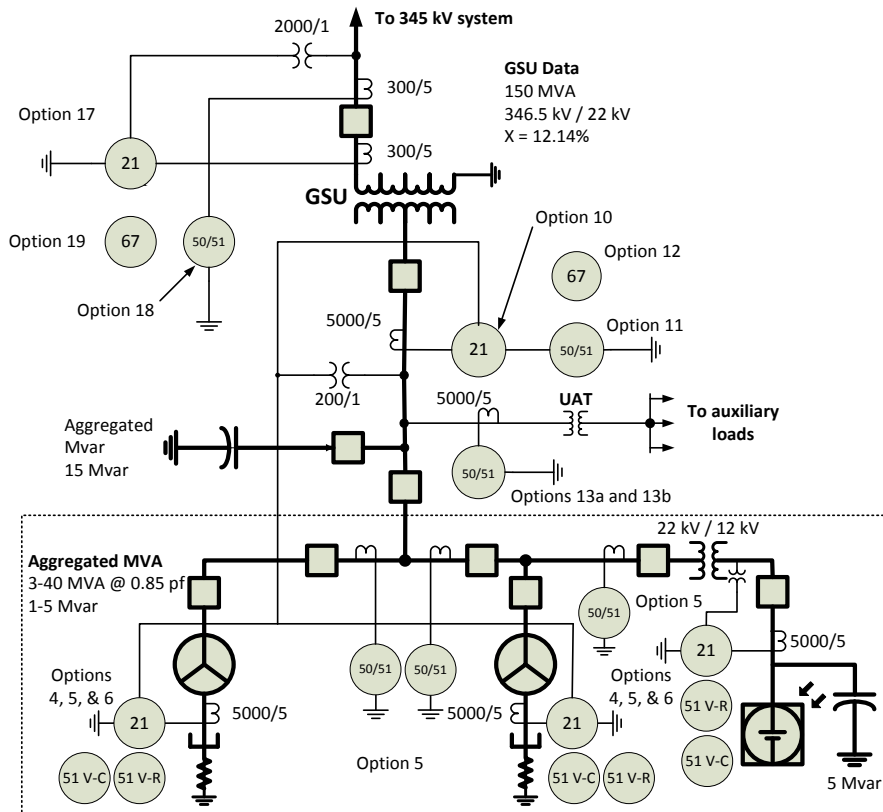


Figure 5-6: Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in [section 3.4 Chapter 2](#) of the [Considerations for](#) Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 0.95 per unit nominal voltage, ~~at the~~ high-side terminals of the GSU transformer ~~times by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

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calculation ~~that approximates~~ is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~ as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more in-depth and~~ precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~ shall be set less than the calculated impedance derived from ~~115 percent~~ 115 percent of ~~both~~: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and ~~the~~ the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~ shall be set less than the calculated impedance derived from 115 percent of ~~both~~: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and ~~the~~ the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – ~~(e.g., 50, 51, or 51V-R – Voltage – Restrained (51V-R))~~ (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of (e.g., 50, 51, or 51V-R – voltage (“voltage-restrained”)-).~~ These margins are based on guidance found in ~~section 3.10~~ Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~ is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

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is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts as well as~~ for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more in-depth and~~ precise ~~method for~~ setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. ~~This output is~~ in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from ~~both~~: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and ~~the~~ Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is shall be~~ set greater than the calculated current derived from 115 percent of ~~both~~: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and ~~the~~ Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (~~e.g.,~~ 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the ~~Considerations for~~ Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 1.0 per unit nominal voltage, ~~at the~~ high-side terminals of the GSU transformer ~~times, by~~ the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is shall be~~ set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (~~e.g.,~~ 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

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Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 1.0 per unit nominal voltage_i at the high-side terminals of the GSU transformer ~~times, by~~ the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage –~~Restrained (51V-R) (Option 5)~~ (Options 5a and 5b)

Table 1, Option 55a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of (e.g., 50, 51, or 51V-R – voltage – (“voltage-restrained”)).~~ These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 55a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 1.0 per unit nominal voltage_i at the high-side terminals of the GSU transformer ~~times, by~~ the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU

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transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option ~~55a~~, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in section 3.10~~Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying at the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer times, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

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Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~ Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying of~~ phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~ and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~ For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ the 0.95 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest calculation that approximates a straightforward way to approximate~~ the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~at the~~ the 0.85 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer and accounts for, as well as~~ the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more in-depth and~~ precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more in-depth and~~ precise method for setting ~~of the overcurrent impedance element overall than Options 7a or 7b.~~

For Options 7a and 7b, the impedance element ~~is shall be~~ set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value, ~~derived from the generator nameplate MVA rating at rated power factor).~~

For Option 7c, the impedance element ~~is shall be~~ set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that

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equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~-Overcurrent Relay (~~e.g., 50 or 51~~) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability ~~for GSU transformers applying of~~ phase ~~time~~-overcurrent relays ~~on synchronous generators~~ that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 0.95 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest calculation that approximates~~ a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~at the~~ 0.85 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer and accounts for, as well as~~ the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more in-depth and~~ precise method for setting ~~of the impedance overcurrent~~ element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more in-depth and~~ precise method for setting ~~of the overcurrent element overall than~~ Options 8a or 8b.

For Options 8a and 8b, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value, ~~derived from the generator nameplate MVA rating at rated power factor.~~

For Option 8c, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~ the Table 1 options differ from ~~section 3.9. Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting loadability~~ threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying of~~ phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~ For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ the 0.95 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest calculation that approximates a straightforward way to approximate~~ the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~at the~~ the 0.85 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer and accounts for, as well as~~ the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more in-depth and~~ precise method for setting ~~of the impedance overcurrent~~ element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more in-depth and~~ precise method for setting ~~of the overcurrent element overall than~~ Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value, ~~(derived from the generator nameplate MVA rating at rated power factor).~~

For Option 9c, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)
The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 ~~Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~ For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying at the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~ is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is shall be~~ set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (~~e.g., 50 or 51~~) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~settingloadability~~ threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying of~~ phase ~~time~~-overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer. ~~Where of an asynchronous generator. For applications where~~ the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is a simple calculation that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; ~~hence~~ the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element ~~is shall be~~ set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (~~e.g., 67~~) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~settingloadability~~ threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability ~~for GSU transformers applying of~~ phase directional ~~time~~-overcurrent relays directional toward the Transmission System ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer of an asynchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~at the~~ 1.0 per unit nominal voltage, ~~at the high-side terminals of the GSU transformer times, by~~ the GSU transformer turns ratio (excluding the impedance). This ~~is a simple calculation that approximates~~ is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; ~~hence~~ the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase ~~Time~~-Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~-overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~-overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~-overcurrent relaying applied ~~at the low-side of~~ the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay

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[Loadability During a Transmission Depressed Voltage Condition, March 2016.](#) These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. ~~Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.~~

Refer to the Figures [67](#) and [78](#) below for example configurations:

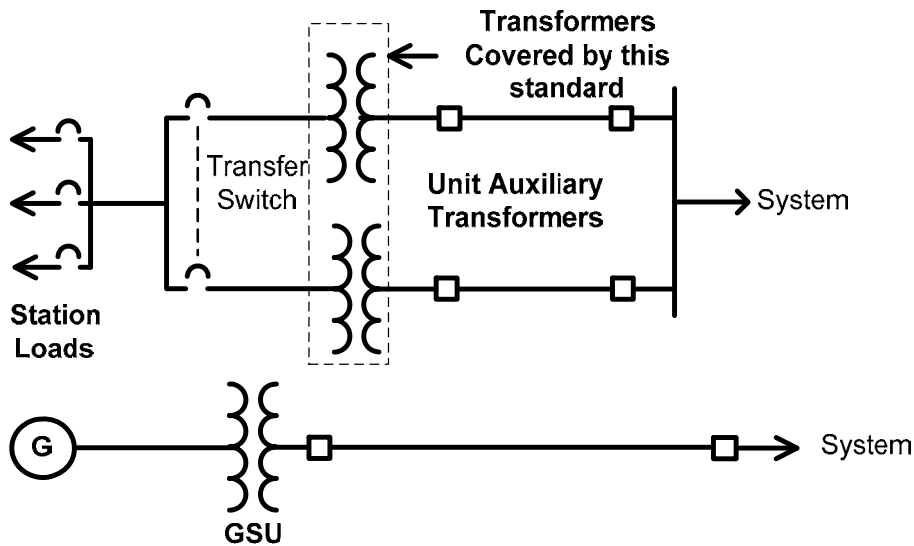


Figure ~~6~~ [7](#): Auxiliary Power System (independent from generator) ~~7.1~~

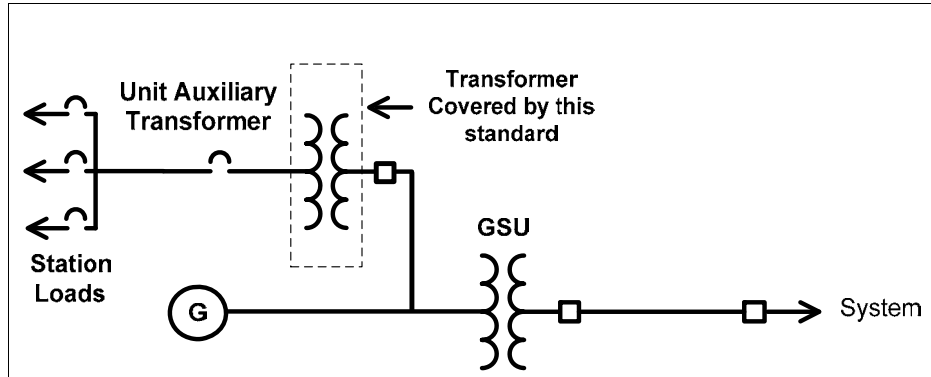


Figure 7-8: Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~-overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the ~~entity's~~ relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

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of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~~~setting~~ current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (~~e.g.,~~ 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~~~Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~~~applied at the remote end of the line for~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~~~tripping~~ during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system of the line nominal~~ voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system of the line nominal~~ voltage ~~at the relay location~~. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high side terminals of the GSU transformer prior to field-forcing, line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

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For Option 14a, the impedance element ~~is shall be~~ set less than the calculated impedance derived from 115 percent of ~~both~~: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and ~~the~~ Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~ applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is shall be~~ set less than the calculated impedance derived from 115 percent of ~~both~~: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and ~~the~~ Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (~~e.g., 50 or 51~~) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~ the Table 1 options differ from ~~section 3.9-Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~ applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating tripping~~ during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system of the line nominal voltage at the relay location~~; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed

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within the criteria, with application of a 0.85 per unit ~~Transmission system of the line nominal voltage at the relay location~~. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing~~ line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from ~~both~~: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and ~~the~~ Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application applications~~ to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from ~~both~~: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and ~~the~~ Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. ~~Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing~~. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~-Overcurrent Relay – Directional Toward Transmission System (~~e.g.,~~ 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~ Table 1 options differ from ~~section 3.9~~ Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~ applied at the remote end of the line for Elements that connect a GSU transformer to the

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Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~ tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system of the line nominal~~ voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system of the line nominal~~ voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field forcing~~ line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~ applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is shall be~~ set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

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Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays ~~applied on~~ installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in section 3.4 ~~Chapter 2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating/tripping~~ during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on at~~ the high-side terminals of the GSU transformer relay location to calculate the impedance from the maximum aggregate nameplate MVA. ~~Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

For Option 17, the impedance element ~~is~~ shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays ~~applied on~~ installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~ the Table 1 options differ from ~~section 3.9~~ Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy

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directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit ~~line~~ nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA. ~~Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (~~e.g.,~~ 67) (Option 19)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9~~Chapter 2 of the ~~Considerations for~~ Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit ~~line~~ nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA. ~~Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	Input Values
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT ~~low~~ <u>high</u> -side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (1)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (2)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (3)} \quad V_{\text{gen}} = 0.95 \text{ p.u.} \times V_{\text{nom}} \times GSU_{\text{ratio}}$$

$$V_{\text{gen}} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{\text{gen}} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (4)} \quad S = P_{\text{Synch\_reported}} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. (5)} \quad Z_{\text{pri}} = \frac{V_{\text{gen}}^2}{S^*}$$

$$Z_{\text{pri}} = \frac{(20.81 \text{ kV})^2}{1347.4 \angle -58.7^\circ \text{ MVA}}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321 \angle 58.7^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (6)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321 \angle 58.7^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321 \angle 58.7^\circ \Omega \times 25$$

$$Z_{sec} = 8.035 \angle 58.7^\circ \Omega$$

To satisfy the 115% margin in Option 1a:

$$\text{Eq. (7)} \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \text{ limit}} = \frac{8.035 \angle 58.7^\circ \Omega}{1.15}$$

$$Z_{sec \text{ limit}} = 6.9873 \angle 58.7^\circ \Omega$$

$$\theta_{transient \text{ load angle}} = 58.7^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85° then the maximum allowable impedance reach is:

$$\text{Eq. (8)} \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})}$$

$$Z_{max} < \frac{6.9873 \Omega}{\cos(85.0^\circ - 58.7^\circ)}$$

$$Z_{max} < \frac{6.9873 \Omega}{0.896}$$

$$Z_{max} < 7.793 \angle 85.0^\circ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (9)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (10)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

$$\text{Eq. (11)} \quad P_{pu} = \frac{P_{\text{Synch\_reported}}}{MVA_{\text{base}}}$$

$$P_{pu} = \frac{700.0 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 0.91 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (12)} \quad Q_{pu} = \frac{Q}{MVA_{\text{base}}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

$$\begin{aligned} \text{Eq. (13)} \quad X_{pu} &= X_{GSU(oid)} \times \left(\frac{MVA_{base}}{MVA_{GSU}} \right) \\ X_{pu} &= 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right) \\ X_{pu} &= 0.1032 \text{ p.u.} \end{aligned}$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). [Estimate/Assume](#) initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\begin{aligned} \text{Eq. (14)} \quad \theta_{low-side} &= \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right] \\ \theta_{low-side} &= \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)} \right] \\ \theta_{low-side} &= 6.7^\circ \end{aligned}$$

[Eq. \(15\)](#)

$$\begin{aligned} \text{Eq. (15)} \quad |V_{low-side}| &= \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} \\ |V_{low-side}| &= \frac{0.85 \times \cos(6.7^\circ) \pm \sqrt{0.85^2 \times \cos^2(6.7^\circ) + 4 \times 1.5 \times 0.1032}}{2} \\ |V_{low-side}| &= \frac{0.85 \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2} \\ |V_{low-side}| &= \frac{0.8441 \pm 1.1541}{2} \\ |V_{low-side}| &= 0.9991 \text{ p.u.} \end{aligned}$$

Deleted Cells

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

$$\text{Eq. (16)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.3^\circ$$

Eq. (17)

$$\text{Eq. (17)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times \cos(6.3^\circ) \pm \sqrt{0.85^2 \times \cos^2(6.3^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998 \text{ p.u.}$$

To account for system high-side nominal voltage and the transformer tap ratio:

$$\text{Eq. (18)} \quad V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.90 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (19)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

$$\begin{aligned} \text{Eq. (20)} \quad Z_{pri} &= \frac{V_{bus}^2}{S^*} \\ Z_{pri} &= \frac{(21.90 \text{ kV})^2}{1347.4 \angle -58.7^\circ \text{ MVA}} \\ Z_{pri} &= 0.356 \angle 58.7^\circ \Omega \end{aligned}$$

Secondary impedance (Z_{sec}):

$$\begin{aligned} \text{Eq. (21)} \quad Z_{sec} &= Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}} \\ Z_{sec} &= 0.356 \angle 58.7^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}} \\ Z_{sec} &= 0.356 \angle 58.7^\circ \Omega \times 25 \\ Z_{sec} &= 8.900 \angle 58.7^\circ \Omega \end{aligned}$$

To satisfy the 115% margin in Options 1b and 7b:

$$\begin{aligned} \text{Eq. (22)} \quad Z_{sec \text{ limit}} &= \frac{Z_{sec}}{115\%} \\ Z_{sec \text{ limit}} &= \frac{8.900 \angle 58.7^\circ \Omega}{1.15} \\ Z_{sec \text{ limit}} &= 7.74 \angle 58.7^\circ \Omega \\ \theta_{transient \text{ load angle}} &= 58.7^\circ \end{aligned}$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~ 85°, then the maximum allowable impedance reach is:

$$\begin{aligned} \text{Eq. (23)} \quad Z_{max} &< \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})} \\ Z_{max} &< \frac{7.74 \Omega}{\cos(85.0^\circ - 58.7^\circ)} \end{aligned}$$

Example Calculations: Options 1b and 7b

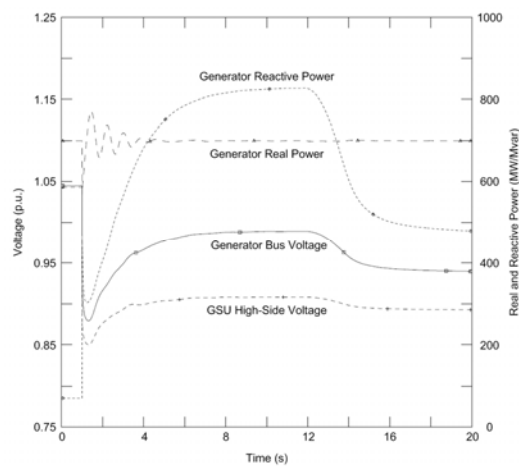
$$Z_{max} < \frac{7.74 \, \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0^\circ \, \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

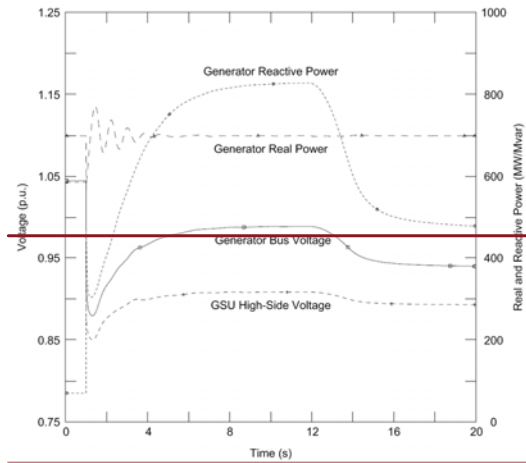
$$Q = 827.4 \text{ Mvar}$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76 \text{ kV}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0 \text{ MW}$$



Apparent power (S):

$$\begin{aligned} \text{Eq. (24)} \quad S &= P_{Synch\_reported} + jQ \\ S &= 700.0 \text{ MW} + j827.4 \text{ Mvar} \\ S &= 1083.8 \angle 49.8^\circ \text{ MVA} \end{aligned}$$

Primary impedance (Z_{pri}):

$$\begin{aligned} \text{Eq. (25)} \quad Z_{pri} &= \frac{V_{bus\_simulated}^2}{S^*} \\ Z_{pri} &= \frac{(21.76 \text{ kV})^2}{1083.8 \angle -49.8^\circ \text{ MVA}} \\ Z_{pri} &= 0.437 \angle 49.8^\circ \Omega \end{aligned}$$

Example Calculations: Options 1c and 7c

Secondary impedance (Z_{sec}):

$$\begin{aligned} \text{Eq. (26)} \quad Z_{sec} &= Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}} \\ Z_{sec} &= 0.437 \angle 49.8^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}} \\ Z_{sec} &= 0.437 \angle 49.8^\circ \Omega \times 25 \\ Z_{sec} &= 10.92 \angle 49.8^\circ \Omega \end{aligned}$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

$$\begin{aligned} \text{Eq. (27)} \quad Z_{sec \text{ limit}} &= \frac{Z_{sec}}{115\%} \\ Z_{sec \text{ limit}} &= \frac{10.92 \angle 49.8^\circ \Omega}{1.15} \\ Z_{sec \text{ limit}} &= 9.50 \angle 49.8^\circ \Omega \\ \theta_{transient \text{ load angle}} &= 49.8^\circ \end{aligned}$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\begin{aligned} \text{Eq. (28)} \quad Z_{max} &< \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{transient \text{ load angle}})} \\ Z_{max} &< \frac{9.50 \Omega}{\cos(85.0^\circ - 49.8^\circ)} \\ Z_{max} &< \frac{9.50 \Omega}{0.8171} \\ Z_{max} &< 11.63 \angle 85.0^\circ \Omega \end{aligned}$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~-overcurrent (e.g., 50, 51, or 51V-R – voltage restrained) ~~voltage restrained~~-relay:

Real Power output (P):

$$\text{Eq. (29)} \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (30)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (31)} \quad V_{\text{gen}} = 0.95 \text{ p.u.} \times V_{\text{nom}} \times GSU_{\text{ratio}}$$

$$V_{\text{gen}} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{\text{gen}} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (32)} \quad S = P_{\text{Synch\_reported}} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (33)} \quad I_{\text{pri}} = \frac{S}{\sqrt{3} \times V_{\text{gen}}}$$

$$I_{\text{pri}} = \frac{1347.4 \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

Example Calculations: Option 2a

$$I_{pri} = 37383 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (34)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.477 \text{ A}$$

To satisfy the 115% margin in Option 2a:

$$\text{Eq. (35)} \quad I_{sec\ limit} > I_{sec} \times 115\%$$

$$I_{sec\ limit} > 7.477 \text{ A} \times 1.15$$

$$I_{sec\ limit} > 8.598 \text{ A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~-overcurrent (e.g., 50, 51, or 51V-R – voltage restrained) ~~voltage restrained~~-relay:

Real Power output (P):

$$\text{Eq. (36)} \quad P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (37)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

$$\text{Eq. (38)} \quad P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 0.91 \text{ p. u.}$$

Reactive Power output (Q):

$$\text{Eq. (39)} \quad Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p. u.}$$

Transformer impedance:

$$\text{Eq. (40)} \quad X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right)$$

$$X_{pu} = 0.1032 \text{ p. u.}$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Estimate-Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\text{Eq. (41)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)} \right]$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7^\circ$$

$$\begin{aligned} \text{Eq. (42)} \quad |V_{low-side}| &= \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} \end{aligned}$$

$$|V_{low-side}| = \frac{0.85 \times \cos(6.7^\circ) \pm \sqrt{0.85^2 \times \cos^2(6.7^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991 \text{ p.u.}$$

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

$$\text{Eq. (43)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.3^\circ$$

$$\begin{aligned} \text{Eq. (44)} \quad |V_{low-side}| &= \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} \end{aligned}$$

$$|V_{low-side}| = \frac{0.85 \times \cos(6.3^\circ) \pm \sqrt{0.85^2 \times \cos^2(6.3^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998 \text{ p.u.}$$

Example Calculations: Option 2b

To account for system high-side nominal voltage and the transformer tap ratio:

$$\text{Eq. (45)} \quad V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.90 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (46)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (47)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 21.90 \text{ kV}}$$

$$I_{pri} = 35553 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (48)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.111 \text{ A}$$

To satisfy the 115% margin in Option 2b:

$$\text{Eq. (49)} \quad I_{sec\ limit} > I_{sec} \times 115\%$$

Example Calculations: Option 2b

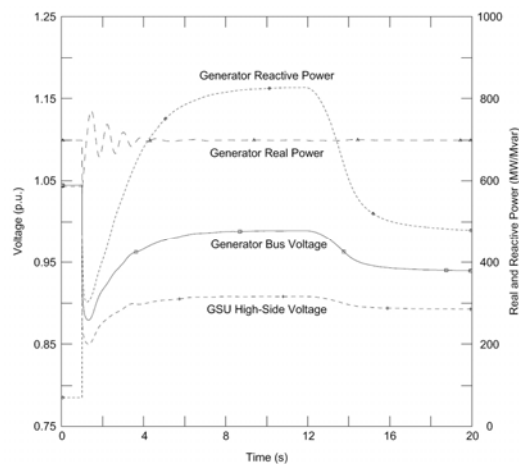
$$I_{seclimit} > 7.111 \text{ A} \times 1.15$$

$$I_{seclimit} > 8.178 \text{ A}$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



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Example Calculations: Option 2c

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

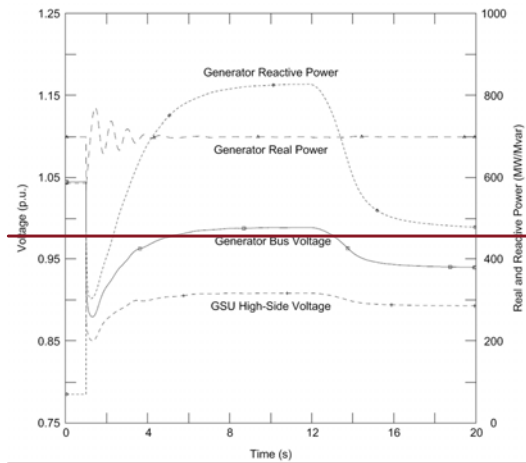
In this simulation the following values are derived:

$$Q = 827.4 \text{ Mvar}$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76 \text{ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0 \text{ MW}$$



Apparent power (S):

$$\text{Eq. (50)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j827.4 \text{ Mvar}$$

$$S = 1083.8 \angle 49.8^\circ \text{ MVA}$$

Example Calculations: Option 2c

Primary current (I_{pri}):

$$\text{Eq. (51)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus, \text{simulated}}}$$

$$I_{pri} = \frac{1083.8 \text{ MVA}}{1.73 \times 21.76 \text{ kV}}$$

$$I_{pri} = 28790 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (52)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 5.758 \text{ A}$$

To satisfy the 115% margin in Option 2c:

$$\text{Eq. (53)} \quad I_{sec \text{ limit}} > I_{sec} \times 115\%$$

$$I_{sec \text{ limit}} > 5.758 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 6.622 \text{ A}$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) ~~voltage-controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (54)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

Example Calculations: Options 3 and 6

$$V_{gen} = 21.9 \text{ kV}$$

The voltage setting shall be set less than 75% of the generator bus voltage:

$$\text{Eq. (55)} \quad V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9 \text{ kV} \times 0.75$$

$$V_{setting} < 16.429 \text{ kV}$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system.

Real Power output (P):

$$\text{Eq. (56)} \quad P = GEN_{Asynch\_nameplate} \times pf$$

$$P = 40 \text{ MVA} \times 0.85$$

$$P = 34.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (57)} \quad Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40 \text{ MVA} \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1 \text{ Mvar}$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (58)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Example Calculations: Option 4

Apparent power (S):

$$\begin{aligned}\text{Eq. (59)} \quad S &= P + jQ \\ S &= 34.0 \text{ MW} + j21.1 \text{ Mvar} \\ S &= 40.0 \angle 31.8^\circ \text{ MVA}\end{aligned}$$

Primary impedance (Z_{pri}):

$$\begin{aligned}\text{Eq. (60)} \quad Z_{pri} &= \frac{V_{gen}^2}{S^*} \\ Z_{pri} &= \frac{(21.9 \text{ kV})^2}{40.0 \angle -31.8^\circ \text{ MVA}} \\ Z_{pri} &= 11.99 \angle 31.8^\circ \Omega\end{aligned}$$

Secondary impedance (Z_{sec}):

$$\begin{aligned}\text{Eq. (61)} \quad Z_{sec} &= Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}} \\ Z_{sec} &= 11.99 \angle 31.8^\circ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}} \\ Z_{sec} &= 11.99 \angle 31.8^\circ \Omega \times 5 \\ Z_{sec} &= 59.95 \angle 31.8^\circ \Omega\end{aligned}$$

To satisfy the 130% margin in Option 4:

$$\begin{aligned}\text{Eq. (62)} \quad Z_{sec\ limit} &= \frac{Z_{sec}}{130\%} \\ Z_{sec\ limit} &= \frac{59.95 \angle 31.8^\circ \Omega}{1.30} \\ Z_{sec\ limit} &= 46.12 \angle 31.8^\circ \Omega \\ \theta_{transient\ load\ angle} &= 31.8^\circ\end{aligned}$$

Example Calculations: Option 4

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\begin{aligned} \text{Eq. (63)} \quad Z_{max} &< \frac{|Z_{sec limit}|}{\cos(\theta_{MTA} - \theta_{transient load angle})} \\ Z_{max} &< \frac{46.12 \, \Omega}{\cos(85.0^\circ - 31.8^\circ)} \\ Z_{max} &< \frac{46.12 \, \Omega}{0.599} \\ Z_{max} &< 77.0 \angle 85.0^\circ \, \Omega \end{aligned}$$

Example Calculations: Option 5₁

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage-restrained~~ relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\begin{aligned} \text{Eq. (64)} \quad P &= 3 \times GEN_{Asynch\_nameplate} \times pf \\ P &= 3 \times 40 \, MVA \times 0.85 \\ P &= 102.0 \, MW \end{aligned}$$

Reactive Power output (Q):

$$\begin{aligned} \text{Eq. (65)} \quad Q &= MVAR_{static} \\ &+ MVAR_{gen\_static} \\ &+ (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))) \\ Q &= 15 \, Mvar + 5 \, Mvar + (3 \times 40 \, MVA \times \sin(\cos^{-1}(0.85))) \\ Q &= 83.2 \, Mvar \end{aligned}$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (66)} \quad V_{gen} = 1.0 \, p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 5_a

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (67)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (68)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 3473 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (69)} \quad I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2^\circ \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2^\circ \text{ A}$$

To satisfy the 130% margin in Option 5_a:

$$\text{Eq. (70)} \quad I_{sec\ limit} > I_{sec} \times 130\%$$

$$I_{sec\ limit} > 3.473 \angle -39.2^\circ \text{ A} \times 1.30$$

$$I_{sec\ limit} > 4.52 \angle -39.2^\circ \text{ A}$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. (71)} \quad P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \text{ MVA} \times 0.85$$

$$P = 102.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (72)} \quad Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \text{ Mvar}$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (73)} \quad V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (74)} \quad S = P + jQ$$

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (75)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option 5b

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 3473 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (76)} \quad I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2^\circ \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2^\circ \text{ A}$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

~~This~~ These examples represents the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

~~Real Power output (P_{synch}):~~

Real Power output (P_{synch}):

$$\text{Eq. (77)} \quad P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903 \text{ MVA} \times 0.85$$

$$P_{Synch} = 767.6 \text{ MW}$$

Example Calculations: Options 7a and 10Reactive Power output (Q_{Synch}):

$$\text{Eq. } Q_{Synch} = 150\% \times P_{Synch}$$

(7278)

$$Q_{Synch} = 1.50 \times 767.6 \text{ MW}$$

$$Q_{Synch} = 1151.3 \text{ MW}$$

Apparent power (S_{Synch}):

$$\text{Eq. } S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

(7379)

$$S_{Synch} = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

Asynchronous Generation (Option 10)~~Real Power output (P_{Asynch}):~~Real Power output (P_{Asynch}):

$$\text{Eq. } P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

(7480)

$$P_{Asynch} = 3 \times 40 \text{ MVA} \times 0.85$$

$$P_{Asynch} = 102.0 \text{ MW}$$

Reactive Power output (Q_{Asynch}):

$$\text{Eq. } Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

(7581)

$$Q_{Asynch} = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \text{ Mvar}$$

Apparent power (S_{Asynch}):

$$\text{Eq. } S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

(7682)

$$S_{Asynch} = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

$$\text{Eq. } V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

$$\text{Eq. } S = 115\% \times (P_{Synch\_reported} + jQ_{Synch}) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0 \text{ MW} + j1151.3 \text{ Mvar}) + 1.30 \times (102.0 \text{ MW} + j83.2 \text{ Mvar})$$

$$S = 1711.8 \angle 56.8^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. } Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81 \text{ kV})^2}{1711.8 \angle -56.8^\circ \text{ MVA}}$$

$$Z_{pri} = 0.2527 \angle 56.8^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. } Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527 \angle 56.8^\circ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527 \angle 56.8^\circ \Omega \times 25$$

Example Calculations: Options 7a and 10

$$Z_{sec} = 6.32 \angle 56.8^\circ \Omega$$

No additional margin is needed; ~~therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85-84~~ to satisfy the margin requirements in Options 7a and 10:

$$\text{Eq. } (8187) \quad Z_{sec \text{ limit}} = \frac{Z_{sec}}{100\%}$$

$$Z_{sec \text{ limit}} = \frac{6.32 \angle 56.8^\circ \Omega}{1.00}$$

$$Z_{sec \text{ limit}} = 6.32 \angle 56.8^\circ \Omega$$

$$\theta_{\text{transient load angle}} = 56.8^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. } (8288) \quad Z_{max} < \frac{|Z_{sec \text{ limit}}|}{\cos(\theta_{MTA} - \theta_{\text{transient load angle}})}$$

$$Z_{max} < \frac{6.32 \Omega}{\cos(85.0^\circ - 56.8^\circ)}$$

$$Z_{max} < \frac{6.32 \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0^\circ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase time overcurrent (~~e.g., 50, 51, or 67~~) relay. The following uses the $GEN_{\text{Synch\_nameplate}}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

$$\text{Eq. } (8389) \quad P = GEN_{\text{Synch\_nameplate}} \times pf$$

Example Calculations: Options 8a and 9a

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. } Q = 150\% \times P$$

(8490)

$$Q = 1.50 \times 767.6 \text{ MW}$$

$$Q = 1151.3 \text{ Mvar}$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

$$\text{Eq. } V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

(8591)

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P_{synch\_reported} + jQ$$

(8692)

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. } I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

(8793)

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri} = 37383 \text{ A}$$

Example Calculations: Options 8a and 9a

Secondary current (I_{sec}):

$$\begin{aligned} \text{Eq. } (8894) \quad I_{sec} &= \frac{I_{pri}}{CT_{ratio}} \\ I_{sec} &= \frac{37383 \text{ A}}{\frac{25000}{5}} \\ I_{sec} &= 7.477 \text{ A} \end{aligned}$$

To satisfy the 115% margin in Options 8a and 9a:

$$\begin{aligned} \text{Eq. } (895) \quad I_{sec \text{ limit}} &> I_{sec} \times 115\% \\ I_{sec \text{ limit}} &> 7.477 \text{ A} \times 1.15 \\ I_{sec \text{ limit}} &> 8.598 \text{ A} \end{aligned}$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more complex-precise calculation for synchronous generators applying a phase time overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{synchron\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

$$\begin{aligned} \text{Eq. } (9096) \quad P &= GEN_{synchron\_nameplate} \times pf \\ P &= 903 \text{ MVA} \times 0.85 \\ P &= 767.6 \text{ MW} \end{aligned}$$

Reactive Power output (Q):

$$\begin{aligned} \text{Eq. } (9197) \quad Q &= 150\% \times P \\ Q &= 1.50 \times 767.6 \text{ MW} \\ Q &= 1151.3 \text{ Mvar} \end{aligned}$$

Example Calculations: Options 8b and 9b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

$$\text{Eq. (9298)} \quad P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0 \text{ MW}}{767.6 \text{ MVA}}$$

$$P_{pu} = 0.91 \text{ p.u.}$$

Reactive Power output (Q):

$$\text{Eq. (9399)} \quad Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3 \text{ Mvar}}{767.6 \text{ MVA}}$$

$$Q_{pu} = 1.5 \text{ p.u.}$$

Transformer impedance:

$$\text{Eq. (94100)} \quad X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6 \text{ MVA}}{903 \text{ MVA}} \right)$$

$$X_{pu} = 0.1032 \text{ p.u.}$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). Estimate-Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\text{Eq. (95101)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)} \right]$$

Example Calculations: Options 8b and 9b

$$\text{Eq. (96102)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times \cos(6.7^\circ) \pm \sqrt{0.85^2 \times \cos^2(6.7^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991 \text{ p.u.}$$

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

$$\text{Eq. (97103)} \quad \theta_{low-side} = \sin^{-1} \left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)} \right]$$

$$\theta_{low-side} = \sin^{-1} \left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)} \right]$$

$$\theta_{low-side} = 6.3^\circ$$

$$\text{Eq. (98104)} \quad |V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times \cos(6.3^\circ) \pm \sqrt{0.85^2 \times \cos^2(6.3^\circ) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{0.85 \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998 \text{ p.u.}$$

Example Calculations: Options 8b and 9b

To account for system high-side nominal voltage and the transformer tap ratio:

$$\text{Eq. } V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

(99105)

$$V_{bus} = 0.9998 \text{ p.u.} \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{bus} = 21.90 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P_{Synch\_reported} + jQ$$

(400106)

$$S = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. } I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

(401107)

$$I_{pri} = \frac{1347.4 \text{ MVA}}{1.73 \times 21.90 \text{ kV}}$$

$$I_{pri} = 35553 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

(402108)

$$I_{sec} = \frac{35553 \text{ A}}{\frac{25000}{5}}$$

$$I_{sec} = 7.111 \text{ A}$$

Example Calculations: Options 8b and 9b

To satisfy the 115% margin in Options 8b and 9b:

$$\text{Eq. } I_{\text{sec limit}} > I_{\text{sec}} \times 115\%$$

(103109)

$$I_{\text{sec limit}} > 7.111 \text{ A} \times 1.15$$

$$I_{\text{sec limit}} > 8.178 \text{ A}$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~-overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~Real Power output (P_{Synch}):

$$\text{Eq. } P_{\text{Synch}} = GEN_{\text{Synch\_nameplate}} \times pf$$

(104110)

$$P_{\text{Synch}} = 903 \text{ MVA} \times .85$$

$$P_{\text{Synch}} = 767.6 \text{ MW}$$

Reactive Power output (Q_{Synch}):

$$\text{Eq. } Q_{\text{Synch}} = 150\% \times P_{\text{Synch}}$$

(105111)

$$Q_{\text{Synch}} = 1.50 \times 767.6 \text{ MW}$$

$$Q_{\text{Synch}} = 1151.3 \text{ Mvar}$$

Example Calculations: Options 8a, 9a, 11, and 12

Apparent power (S_{Synch}):

$$\text{Eq. } S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

(106112)

$$S_{Synch} = 700.0 \text{ MW} + j1151.3 \text{ Mvar}$$

$$S_{Synch} = 1347.4 \angle 58.7^\circ \text{ MVA}$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

$$\text{Eq. } V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

(107113)

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Primary current ($I_{pri-sync}$):

$$\text{Eq. } I_{pri-sync} = \frac{115\% \times S_{Synch}^*}{\sqrt{3} \times V_{gen}}$$

(108114)

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7^\circ \text{ MVA})}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri-sync} = 43061 \angle -58.7^\circ \text{ A}$$

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~Real Power output (P_{Asynch}):

$$\text{Eq. } P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

(109115)

$$P_{Asynch} = 3 \times 40 \text{ MVA} \times 0.85$$

$$P_{Asynch} = 102.0 \text{ MW}$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Asynch}):

$$\text{Eq. } Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

(116)

$$Q_{Asynch} = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \text{ Mvar}$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

$$\text{Eq. } V_{gen} = 0.95 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

(117)

$$V_{gen} = 0.95 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 20.81 \text{ kV}$$

Apparent power (S_{Asynch}):

$$\text{Eq. } S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

(118)

$$S_{Asynch} = 1.30 \times (102.0 \text{ MW} + j83.2 \text{ Mvar})$$

$$S_{Asynch} = 171.1 \angle 39.2^\circ \text{ MVA}$$

Primary current ($I_{pri-asynch}$):

$$\text{Eq. } I_{pri-asynch} = \frac{S_{Asynch}}{\sqrt{3} \times V_{gen}}$$

(119)

$$I_{pri-asynch} = \frac{171.1 \angle -39.2^\circ \text{ MVA}}{1.73 \times 20.81 \text{ kV}}$$

$$I_{pri-asynch} = 4755 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{sec} = \frac{I_{pri-synch}}{CT_{ratio}} + \frac{I_{pri-asynch}}{CT_{ratio}}$$

(120)

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061 \angle -58.7^\circ A}{\frac{25000}{5}} + \frac{4755 \angle -39.2^\circ A}{\frac{25000}{5}}$$
$$I_{sec} = 9.514 \angle -56.8^\circ A$$

No additional margin is needed; ~~therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94.114~~ and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98.118~~:

Eq. ~~(115.121)~~ $I_{sec limit} > I_{sec} \times 100\%$

$$I_{sec limit} > 9.514 \angle -56.8^\circ A \times 1.00$$
$$I_{sec limit} > 9.514 \angle -56.8^\circ A$$

Example Calculations: Options 8c and 9c

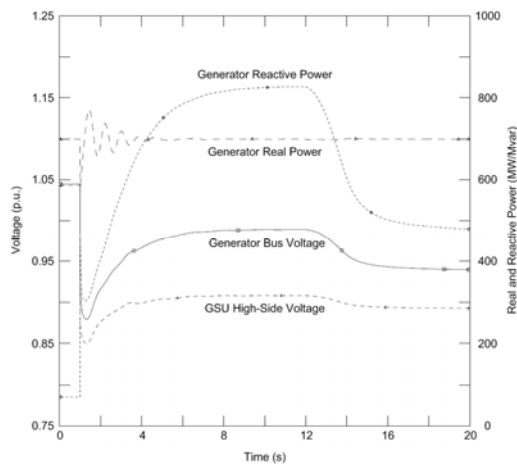
This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~-overcurrent relay; ~~(e.g., 50, 51, or 67)~~. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, ~~during field-forcing,~~ is used ~~as~~ ~~since~~ this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

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Example Calculations: Options 8c and 9c

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In this simulation the following values are derived:

$$Q = 827.4 \text{ Mvar}$$

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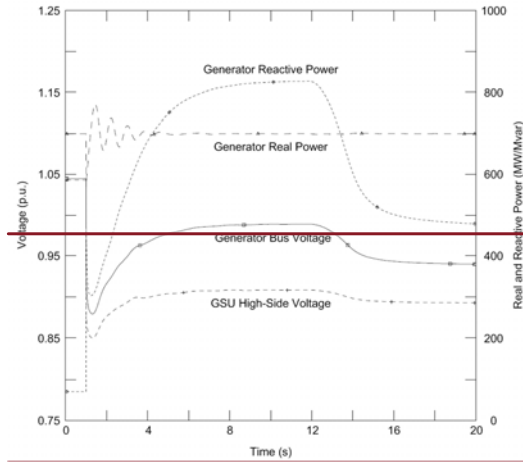
$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76 \text{ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \text{ MW}$$

Example Calculations: Options 8c and 9c

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Apparent power (S):

$$\text{Eq. } S = P_{\text{synch\_reported}} + jQ$$

(116122)

$$S = 700.0 \text{ MW} + j827.4 \text{ Mvar}$$

$$S = 1083.8 \angle 49.8^\circ$$

Primary current (I_{pri}):

$$\text{Eq. } I_{\text{pri}} = \frac{S}{\sqrt{3} \times V_{\text{bus\_simulated}}}$$

(117123)

$$I_{\text{pri}} = \frac{1083.8 \text{ MVA}}{1.73 \times 21.76 \text{ kV}}$$

$$I_{\text{pri}} = 28790 \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{\text{sec}} = \frac{I_{\text{pri}}}{CT_{\text{ratio}}}$$

(118124)

$$I_{\text{sec}} = \frac{28790 \text{ A}}{\frac{25000}{5}}$$

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Example Calculations: Options 8c and 9c

$$I_{sec} = 5.758 \text{ A}$$

To satisfy the 115% margin in Options 8c and 9c:

$$\text{Eq. } I_{sec \text{ limit}} > I_{sec} \times 115\%$$

(449125)

$$I_{sec \text{ limit}} > 5.758 \text{ A} \times 1.15$$

$$I_{sec \text{ limit}} > 6.622 \text{ A}$$

Example Calculations: Option10

This [examples](#) represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay ([e.g., 21](#)) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. } P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

(420126)

$$P = 3 \times 40 \text{ MVA} \times 0.85$$

$$P = 102.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. } Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

(424127)

$$Q = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \text{ Mvar}$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. } V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

(422128)

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Example Calculations: Option10

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P + jQ$$

(123129)

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

$$\text{Eq. } Z_{pri} = \frac{V_{gen}^2}{S^*}$$

(124130)

$$Z_{pri} = \frac{(21.9 \text{ kV})^2}{131.6 \angle -39.2^\circ \text{ MVA}}$$

$$Z_{pri} = 3.644 \angle 39.2^\circ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. } Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

(125131)

$$Z_{sec} = 3.644 \angle 39.2^\circ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644 \angle 39.2^\circ \Omega \times 5$$

$$Z_{sec} = 18.22 \angle 39.2^\circ \Omega$$

To satisfy the 130% margin in Option 10:

$$\text{Eq. } Z_{seclimit} = \frac{Z_{sec}}{130\%}$$

(126132)

$$Z_{seclimit} = \frac{18.22 \angle 39.2^\circ \Omega}{1.30}$$

$$Z_{seclimit} = 14.02 \angle 39.2^\circ \Omega$$

Example Calculations: Option10

$$\theta_{transient\ load\ angle} = 39.2^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. } Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0^\circ - 39.2^\circ)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11 \angle 85.0^\circ\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~-overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. } P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

$$\text{Eq. } Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Options 11 and 12

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. } V_{gen} = 1.0 \text{ p.u.} \times V_{nom} \times GSU_{ratio}$$

(130136)

$$V_{gen} = 1.0 \times 345 \text{ kV} \times \left(\frac{22 \text{ kV}}{346.5 \text{ kV}} \right)$$

$$V_{gen} = 21.9 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P + jQ$$

(131137)

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. } I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

(132138)

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 21.9 \text{ kV}}$$

$$I_{pri} = 3473 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

(133139)

$$I_{sec} = \frac{3473 \angle -39.2^\circ \text{ A}}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2^\circ \text{ A}$$

To satisfy the 130% margin in Options 11 and 12:

$$\text{Eq. } I_{sec\ limit} > I_{sec} \times 130\%$$

(134140)

Example Calculations: Options 11 and 12

$$I_{sec\ limit} > 3.473 \angle -39.2^\circ A \times 1.30$$

$$I_{sec\ limit} > 4.515 \angle -39.2^\circ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

$$\text{Eq. } I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ A$$

To satisfy the 150% margin in Options 13a:

$$\text{Eq. } I_{sec\ limit} > I_{sec} \times 150\%$$

$$I_{sec\ limit} > 2.51\ A \times 1.50$$

$$I_{sec\ limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~ relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that ~~connected to synchronous generation. In this example, the Element is applying~~ protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

$$\text{Eq. } P = GEN_{\text{synch\_nameplate}} \times pf$$

(138144)

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. } Q = 120\% \times P$$

(139145)

$$Q = 1.20 \times 767.6 \text{ MW}$$

$$Q = 921.1 \text{ Mvar}$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high-side~~ nominal voltage for the GSU transformer voltage (V_{nom}):

$$\text{Eq. } V_{\text{bus}} = 0.85 \text{ p.u.} \times V_{\text{nom}}$$

(140146)

$$V_{\text{gen}} = 0.85 \times 345 \text{ kV}$$

$$V_{\text{gen}} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P_{\text{synch\_reported}} + jQ$$

(141147)

$$S = 700.0 \text{ MW} + j921.1 \text{ Mvar}$$

$$S = 1157.0 \angle 52.77^\circ \text{ MVA}$$

Example Calculations: Option 14a

$$\theta_{transient\ load\ angle} = 52.77^\circ$$

Primary impedance (Z_{pri}):

$$\text{Eq. (142)} \quad Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0 \angle -52.77^\circ\ MVA}$$

$$Z_{pri} = 74.335 \angle 52.77^\circ\ \Omega$$

Secondary impedance (Z_{sec}):

$$\text{Eq. (143)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335 \angle 52.77^\circ\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335 \angle 52.77^\circ\ \Omega \times 0.2$$

$$Z_{sec} = 14.867 \angle 52.77^\circ\ \Omega$$

To satisfy the 115% margin in Option 14a:

$$\text{Eq. (144)} \quad Z_{sec\ limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\ limit} = \frac{14.867 \angle 52.77^\circ\ \Omega}{1.15}$$

$$Z_{sec\ limit} = 12.928 \angle 52.77^\circ\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. (145)} \quad Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0^\circ - 52.77^\circ)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928 \Omega}{0.846}$$

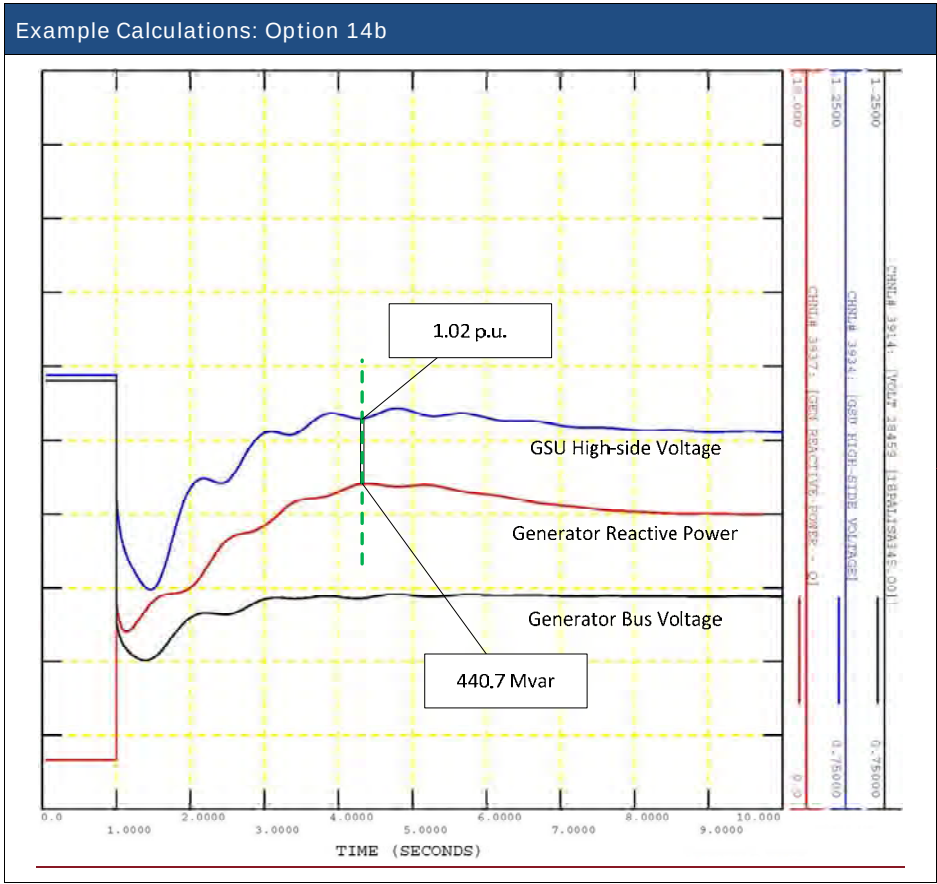
$$Z_{max} < 15.283 \angle 85.0^\circ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~ relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that connected to synchronous generation. In this example, the Element is applying~~ protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and ~~high-side bus voltage~~ coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~ these values will correspond to the lowest apparent impedance, ~~at the relay location~~. The corresponding ~~high-side bus~~ simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

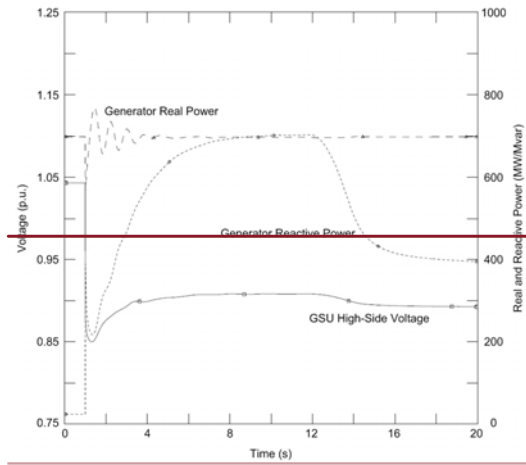
$$Q = 703.6 \text{ Mvar}$$
$$V_{bus} = 0.908 \times V_{nom} = 313.3 \text{ kV}$$

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Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \text{ MW}$$



Apparent power (S):

$$\text{Eq. (146152)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j703.6 \text{ Mvar}$$

$$S = 992.5 \angle 45.1^\circ \text{ MVA}$$

$$\theta_{transient \text{ load angle}} = 45.1^\circ$$

Primary impedance (Z_{pri}):

$$\text{Eq. (147153)} \quad Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3 \text{ kV})^2}{992.5 \angle -45.1^\circ \text{ MVA}}$$

$$Z_{pri} = 98.90 \angle 45.1^\circ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

$$\text{Eq. (148)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio,hv}}{PT_{ratio,hv}}$$

$$Z_{sec} = 98.90 \angle 45.1^\circ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90 \angle 45.1^\circ \Omega \times 0.2$$

$$Z_{sec} = 19.78 \angle 45.1^\circ \Omega$$

To satisfy the 115% margin in Option 14b:

$$\text{Eq. (149)} \quad Z_{sec\ limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\ limit} = \frac{19.78 \angle 45.1^\circ \Omega}{1.15}$$

$$Z_{sec\ limit} = 17.20 \angle 45.1^\circ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1^\circ$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , then the maximum allowable impedance reach is:

$$\text{Eq. (150)} \quad Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20 \Omega}{\cos(85.0^\circ - 45.1^\circ)}$$

$$Z_{max} < \frac{17.20 \Omega}{0.767}$$

$$Z_{max} < 22.42 \angle 85.0^\circ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line,~~ for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~connected to synchronous generation.~~

Option 15a represents applying a phase time overcurrent relay (e.g., 51) ~~and/or Phase~~ instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer ~~including relays installed at the remote end of the line.~~

Option 16a represents applying a phase directional ~~time overcurrent relay or Phase~~ directional instantaneous overcurrent supervisory ~~elements (element~~ (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system— installed on the high-side of the GSU ~~and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.~~

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer. Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.~~

Calculations at the high-side of the GSU transformer.

Real Power output (P):

$$\text{Eq. } P = GEN_{\text{synch\_nameplate}} \times pf$$

(154157)

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. } Q = 120\% \times P$$

(152158)

$$Q = 1.20 \times 767.6 \text{ MW}$$

Example Calculations: Options 15a and 16a

$$Q = 921.12 \text{ Mvar}$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

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$$\text{Eq. } V_{bus} = 0.85 \text{ p.u.} \times V_{nom}$$

(153159)

$$V_{bus} = 0.85 \times 345 \text{ kV}$$

$$V_{bus} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P_{Synch\_reported} + jQ$$

(154160)

$$S = 700.0 \text{ MW} + j921.12 \text{ Mvar}$$

$$S = 1157 \angle 52.8^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. } I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

(155161)

$$I_{pri} = \frac{1157 \angle -52.8^\circ \text{ MVA}}{1.73 \times 293.25 \text{ kV}}$$

$$I_{pri} = 2280.6 \angle -52.8^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

(156162)

$$I_{sec} = \frac{2280.6 \angle -52.8^\circ \text{ A}}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8^\circ \text{ A}$$

To satisfy the 115% margin in Options 15a and 15b:

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$$\text{Eq. } I_{sec\ limit} > I_{sec} \times 115\%$$

(157163)

Example Calculations: Options 15a and 16a

$$I_{sec\ limit} > 5.701 \angle -52.8^\circ A \times 1.15$$

$$I_{sec\ limit} > 6.56 \angle -52.8^\circ A$$

Calculations at the remote end of the line from the plant.

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Real Power output (P):

$$\text{Eq. (164)} \quad P = GEN_{synch\_nameplate} \times pf$$

$$P = 903 \text{ MVA} \times 0.85$$

$$P = 767.6 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. (165)} \quad Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \text{ MW}$$

$$Q = 921.12 \text{ Mvar}$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

$$\text{Eq. (166)} \quad V_{bus\_remote\_substation} = 0.85 \text{ p.u.} \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345 \text{ kV}$$

$$V_{bus\_remote\_substation} = 293.25 \text{ kV}$$

Apparent power (S):

$$\text{Eq. (167)} \quad S = P_{synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j921.12 \text{ Mvar}$$

$$S = 1157 \angle 52.8^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (168)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157 \angle -52.8^\circ \text{ MVA}}{1.73 \times 293.25 \text{ kV}}$$

$$I_{pri} = 2280.6 \angle -52.8^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. (169)} \quad I_{sec} = \frac{I_{pri}}{CT_{CTratio\_remote\_bus}}$$

$$I_{sec} = \frac{2280.6 \angle -52.8^\circ \text{ A}}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8^\circ \text{ A}$$

To satisfy the 115% margin in Options 15a and 16a:

$$\text{Eq. (170)} \quad I_{seclimit} > I_{sec} \times 115\%$$

$$I_{seclimit} > 5.701 \angle -52.8^\circ \text{ A} \times 1.15$$

$$I_{seclimit} > 6.56 \angle -52.8^\circ \text{ A}$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~ relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant—~~connected to synchronous generation.~~

Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~ ~~instantaneous~~ overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications—installed on the high-side of the GSU transformer—, including relays at the remote end of the line.

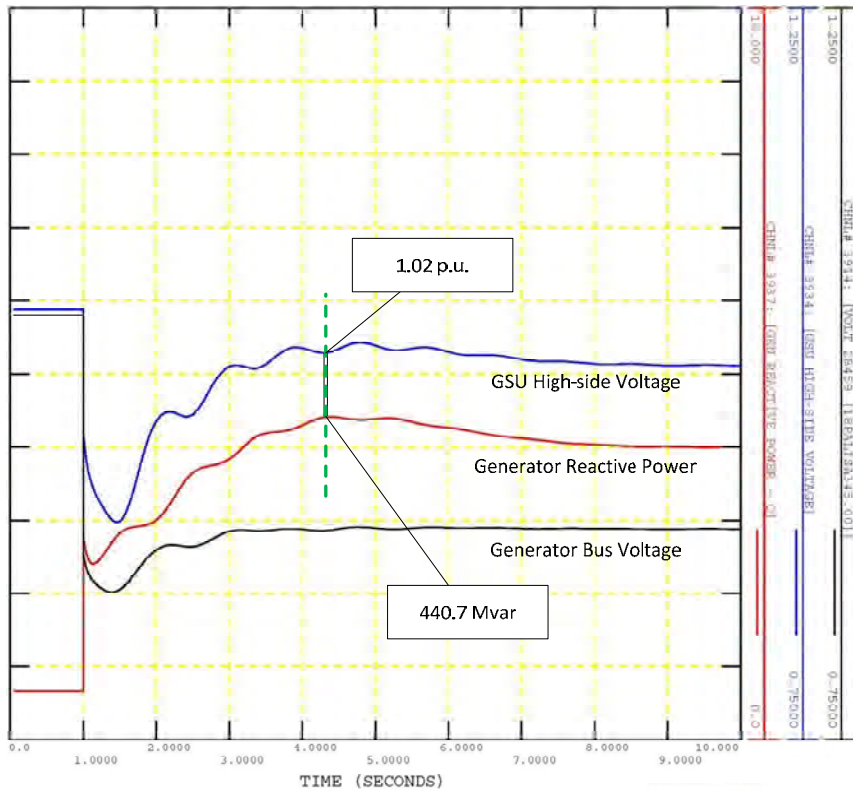
Option 16b represents applying a phase directional ~~time overcurrent relay or Phase~~ ~~directional~~ ~~instantaneous~~ overcurrent supervisory ~~elements (element~~ (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications—directional toward the Transmission system— and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side bus voltage of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~ these values will correspond to the lowest apparent impedance— at the relay location. The corresponding high-side bus simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

In this simulation the following values are derived:

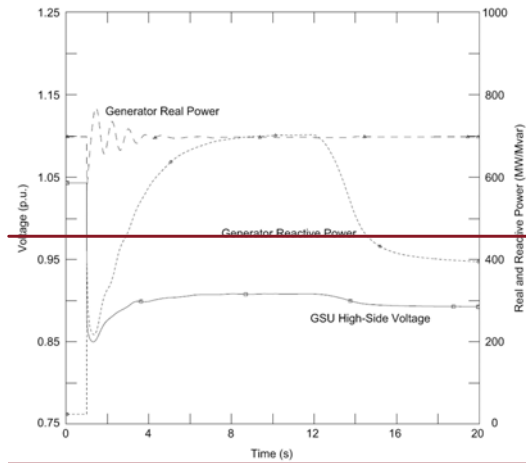
$$Q = 703.6 \text{ Mvar}$$

$$V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3 \text{ kV}$$

Example Calculations: Options 15b and 16b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0 \text{ MW}$$



Apparent power (S):

$$\text{Eq. (158171)} \quad S = P_{synch\_reported} + jQ$$

$$S = 700.0 \text{ MW} + j703.6 \text{ Mvar}$$

$$S = 992.5 \angle 45.1^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. (159172)} \quad I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{992.5 \angle -45.1^\circ \text{ MVA}}{1.73 \times 313.3 \text{ kV}}$$

$$I_{pri} = 1831.2 \angle -45.1^\circ \text{ A}$$

Example Calculations: Options 15b and 16b

Secondary current (I_{sec}):

$$\begin{aligned} \text{Eq. (160173)} \quad I_{sec} &= \frac{I_{pri}}{CT_{ratio\_hv}} \\ I_{sec} &= \frac{1831.2 \angle -45.1^\circ A}{\frac{2000}{5}} \\ I_{sec} &= 4.578 \angle -45.1^\circ A \end{aligned}$$

To satisfy the 115% margin in Options 15b and 16b:

$$\begin{aligned} \text{Eq. (161174)} \quad I_{sec\ limit} &> I_{sec} \times 115\% \\ I_{sec\ limit} &> 4.578 \angle -45.1^\circ A \times 1.15 \\ I_{sec\ limit} &> 5.265 \angle -45.1^\circ A \end{aligned}$$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\begin{aligned} \text{Eq. (162175)} \quad P_{Asynch} &= 3 \times GEN_{Asynch\_nameplate} \times pf \\ P_{Asynch} &= 3 \times 40\ MVA \times 0.85 \\ P_{Asynch} &= 102.0\ MW \end{aligned}$$

Reactive Power output (Q):

$$\begin{aligned} \text{Eq. (163176)} \quad Q_{Asynch} &= MVAR_{static} + MVAR_{gen\_static} \\ &+ (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))) \end{aligned}$$

Example Calculations: Option 17

$$Q_{Asynch} = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \text{ Mvar}$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. $V_{bus} = 1.0 \text{ p.u.} \times V_{nom}$
(164177)

$$V_{gen} = 1.0 \times 345 \text{ kV}$$

$$V_{gen} = 345.0 \text{ kV}$$

Apparent power (S):

Eq. $S = P + jQ$
(165178)

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary impedance (Z_{pri}):

Eq. $Z_{pri} = \frac{V_{bus}^2}{S^*}$
(166179)

$$Z_{pri} = \frac{(345.0 \text{ kV})^2}{131.6 \angle -39.2^\circ \text{ MVA}}$$

$$Z_{pri} = 904.4 \angle 39.2^\circ \Omega$$

Secondary impedance (Z_{sec}):

Eq. $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$
(167180)

$$Z_{sec} = 904.4 \angle 39.2^\circ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4 \angle 39.2^\circ \Omega \times 0.03$$

$$Z_{sec} = 27.13 \angle 39.2^\circ \Omega$$

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Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

$$\begin{aligned} \text{Eq. (168)(181)} \quad Z_{\text{sec limit}} &= \frac{Z_{\text{sec}}}{130\%} \\ Z_{\text{sec limit}} &= \frac{27.13 \angle 39.2^\circ \Omega}{1.30} \\ Z_{\text{sec limit}} &= 20.869 \angle 39.2^\circ \Omega \\ \theta_{\text{transient load angle}} &= 39.2^\circ \end{aligned}$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85° , and then the maximum allowable impedance reach is:

$$\begin{aligned} \text{Eq. (169)(182)} \quad Z_{\text{max}} &< \frac{|Z_{\text{sec limit}}|}{\cos(\theta_{\text{MTA}} - \theta_{\text{transient load angle}})} \\ Z_{\text{max}} &< \frac{20.869 \Omega}{\cos(85.0^\circ - 39.2^\circ)} \\ Z_{\text{max}} &< \frac{20.869 \Omega}{0.697} \\ Z_{\text{max}} &< 29.941 \angle 85.0^\circ \Omega \end{aligned}$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three-generation Elements that connect a relays on relays installed on the high-side of the~~ GSU transformer, ~~including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators~~ to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~.

Option 18 represents applying a phase time overcurrent (e.g., 51) relay connected to three asynchronous generators, and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~-overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that

Example Calculations: Options 18 and 19

are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$\text{Eq. } P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

(170183)

$$P = 3 \times 40 \text{ MVA} \times 0.85$$

$$P = 102.0 \text{ MW}$$

Reactive Power output (Q):

$$\text{Eq. } Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

(171184)

$$Q = 15 \text{ Mvar} + 5 \text{ Mvar} + (3 \times 40 \text{ MVA} \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \text{ Mvar}$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

$$\text{Eq. } V_{nom} = 1.0 \text{ p.u.} \times V_{nom}$$

(172185)

$$V_{bus} = 1.0 \times 345 \text{ kV}$$

$$V_{bus} = 345 \text{ kV}$$

Apparent power (S):

$$\text{Eq. } S = P + jQ$$

(173186)

$$S = 102.0 \text{ MW} + j83.2 \text{ Mvar}$$

$$S = 131.6 \angle 39.2^\circ \text{ MVA}$$

Primary current (I_{pri}):

$$\text{Eq. } I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

(174187)

Example Calculations: Options 18 and 19

$$I_{pri} = \frac{131.6 \angle -39.2^\circ \text{ MVA}}{1.73 \times 345 \text{ kV}}$$

$$I_{pri} = 220.5 \angle -39.2^\circ \text{ A}$$

Secondary current (I_{sec}):

$$\text{Eq. } I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5 \angle -39.2^\circ \text{ A}}{\frac{300}{5}}$$

$$I_{sec} = 3.675 \angle -39.2^\circ \text{ A}$$

To satisfy the 130% margin in Options 18 and 19:

$$\text{Eq. } I_{sec\ limit} > I_{sec} \times 130\%$$

$$I_{sec\ limit} > 3.675 \angle -39.2^\circ \text{ A} \times 1.30$$

$$I_{sec\ limit} > 4.778 \angle -39.2^\circ \text{ A}$$

End of calculations

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:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-~~4-25~~
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
 - 4.1. Transmission Operators
 - 4.2. Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date**^{*}~~:~~
 - 5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

^{*}~~Mandatory BC Effective Date: October 1, 2018~~

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for

generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having it automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

- R5.** Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

- M5.** The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

- R6.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical

justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M6.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

~~The British Columbia Utilities Commission~~
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to 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 a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None

~~VAR-001-4.2— Voltage and Reactive Control~~~~VAR-001-5— Voltage and Reactive Control~~**Table of Compliance Elements**

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	Real-time Operations, Same-day Operations, and Operations Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

~~VAR-001-4.2 — Voltage and Reactive Control~~

~~VAR-001-5 — Voltage and Reactive Control~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

~~VAR-001-4.2 — Voltage and Reactive Control~~

~~VAR-001-5 — Voltage and Reactive Control~~

<u>R5</u>	<u>Operations Planning</u>	<u>Medium</u>	<u>N/A</u>	<u>The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.</u>	<u>The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.</u>	<u>The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators.</u> <u>Or</u> <u>The Transmission Operator does not provide the Generator Operator with the notification</u>

~~VAR-001-4.2 — Voltage and Reactive Control~~
~~VAR-001-5 — Voltage and Reactive Control~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

~~VAR-001-4.2 — Voltage and Reactive Control~~

~~VAR-001-5 — Voltage and Reactive Control~~

R-#	Time-Horizon	VRF	Violation-Severity-Levels			
			Lower-VSL	Moderate-VSL	High-VSL	Severe-VSL
R6	Operations Planning	Lower	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

~~VAR-001-4.2— Voltage and Reactive Control~~~~VAR-001-5— Voltage and Reactive Control~~

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements and Measures

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

M.E.A.13 Each Transmission Operator will have evidence that it provided the voltage schedules to the Generator Operator, as required in E.A.13. Evidence may include, but is not limited to, dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its ~~Area~~area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

~~**E.A.13** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*~~

M.E.A.14 The Transmission Operator will have evidence that it provided one of the voltage schedule reference points for each generation resource in its area to the Generator Operator, as required in E.A.14. Evidence may include, but is not limited to dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource.

E.A.15 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~VAR-001-4.2— Voltage and Reactive Control~~

~~VAR-001-5— Voltage and Reactive Control~~

M.E.A.15 The Generator Operator will have evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals, as required in E.A.15. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.16 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

M.E.A.16 The Transmission Operator will have evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology, as required in E.A.16. Evidence may include, but is not limited to, dated reports, spreadsheets, or other documentation.

E.A.17 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

E.A.17.1 Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.17.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures¹

~~Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement~~

~~**M.E.A.13— M.E.A.13 are acceptable as evidence.**~~

~~**M.E.A.14** The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.~~

~~**M.E.A.15** Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.~~

~~**M.E.A.16** The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~**M.E.A.17** The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.~~

~~VAR-001-4.2— Voltage and Reactive Control~~

~~VAR-001-5— Voltage and Reactive Control~~

-
- 17** If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator ~~shall~~will have ~~and provide upon request,~~ evidence that it met the control loop specifications in sub-parts E.A.~~1817~~.1 through E.A.~~1817~~.2. ~~Design, as required in E.A.17 and its sub-parts. Evidence may include, but is not limited to, design~~ specifications with identified agreed-upon control loops, system reports, or other dated documentation ~~are acceptable as evidence.~~

[†]The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.

<u>E #</u>	<u>Lower VSL</u>	<u>Moderate VSL</u>	<u>High VSL</u>	<u>Severe VSL</u>
<u>E.A.15</u>	<u>The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.</u>	<u>The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.</u>	<u>The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.</u>	<u>The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.</u>
<u>E.A.1516</u>	<u>The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules. The Transmission Operator provided its data to support development of</u>	<u>The Generator Transmission Operator failed to provide its data to convert the voltage schedules in Requirement E.A.13 into support development of the voltage set point for the AVR for 25% or more conversion methodology</u>	<u>The Generator Transmission Operator failed to provide its data to convert the voltage schedules in Requirement E.A.13 into support development of the voltage set point for the AVR for 50% or more conversion methodology</u>	<u>The Generator Transmission Operator failed to provide its data to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more support development of the voltage</u>
<u>E.A.17</u>	<u>N/A</u>	<u>The Generator Operator did not meet the control loop specifications in E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</u>	<u>The Generator Operator did not meet the control loop specifications in E.A.17.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</u>	<u>The Generator Operator did not meet the control loop specifications in E.A.17.1 through E.A.17.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</u>

E #	Lower-VSL	Moderate-VSL	High-VSL	Severe-VSL
E.A.16	~~The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.~~	~~The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.~~	~~The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.~~	~~The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.~~
E.A.17	~~The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.~~	~~The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator Operator.~~	~~The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator Operator.~~	~~The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.~~
E.A.18	N/A	~~The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.~~	~~The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.~~	~~The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.~~

E. Interpretations

None

F. Associated Documents

Non
e.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January 7, 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata
4.2	September 26, 2017	FERC Letter Order issued approving VAR-001-4.2 Docket No. RD17-7-000.	
<u>5</u>	<u>August 16, 2018</u>	<u>Adopted by NERC Board of Trustees</u>	<u>1) In E.A.14 “Area” was</u>

				<u>"area."; 2) E.A.15 and associated elements were eliminated; 3) Measures were updated and relocated matching current conventions, replacing "shall" with "will"; 4) typographical errors in VSL Table for E.A.17 were corrected;</u>
<u>5</u>	<u>10/15/2018</u>	<u>FERC Order issued approving VAR-001-5 Docket No. RD18-8-000.</u>		

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

Rationale:

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

Rationale for R1:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post- Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post- Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage

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schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Mandatory Reliability Standards Assessment Report No. 12

Appendix B

**NERC Glossary of Terms used in Reliability Standards,
Updated July 3, 2018**

Glossary of Terms Used in NERC Reliability Standards

Updated July 3, 2018

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 July 3, 2018.

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 following:
sarcomm@nerc.net with "Glossary Comment" in the subject line.

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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
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	Version 0 Reliability Standards	AGC	2/8/2005	3/16/2007		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.
Automatic Time Error Correction (I _{ATEC}) <i>continued below...</i>	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. $I_{ATEC} = \frac{PII_{hourly}^{on/off peak}}{(1-Y) \cdot H}$ when 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. • L₁₀ = 1.65 * ε₁₀ √((-10B_i)(-10B_s)). • ε₁₀ is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε₁₀, is the same for every Balancing Authority Area within an Interconnection.
Automatic Time Error Correction (I _{ATEC})	Project 2010-14.2.1. Phase 2		2/11/2016		7/1/2016	• Y = B_i / B_s. • 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). • PII_{hourly} is the hourly Inadvertent Interchange for the last hour. • I_{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})

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	• 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 PII_{hourly} in MWh. An On-Peak and Off-Peak accumulation accounting is required, where: $PII_{accum}^{on/offpeak} = \text{last period's } PII_{accum}^{on/offpeak} + PII_{hourly}$
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.
Balancing Authority	Version 0 Reliability Standards	BA	2/8/2005	3/16/2007		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.
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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
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		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 Implementation 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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
Bulk Electric System (continued below)	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation 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.
Bulk Electric System (continued)	Project 2010-17	BES	11/21/2013	3/20/2014	7/1/2014 (Please see the Implementation 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 Implementation 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.

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 Implementation 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 Implementation 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.
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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
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.
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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
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.
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.
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.
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.

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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).
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.
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.

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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 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.
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.
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.
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.
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.

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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.
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.

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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.
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.
Generator Owner	Version 0	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.
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.
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		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.

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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.
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.

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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.
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.

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Low Impact BES Cyber System Electronic Access Point	Project 2014-02	LEAP	2/12/2015	1/21/2016	7/1/2016	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	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).
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.

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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.

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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.
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 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.
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 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.
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.)

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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.
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.

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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.
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.

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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.
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.

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Pseudo-Tie	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 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).
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
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.
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.
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.)

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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.
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.

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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

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Remedial Action Scheme <i>Continued</i>	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 <i>Continued</i>	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 2014-02		2/12/2015	1/21/2016	7/1/2016	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.
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

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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: $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$ 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.

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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.

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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.
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.

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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.
Telemetry	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.
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.

SUBJECT TO ENFORCEMENT						
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Definition
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 <i>in a reliable manner</i> 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 <i>not</i> generally 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.
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.
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.

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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.
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.

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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						
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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.
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.
Operational Planning Analysis	Project 2007-06.2 Phase 2 of System Protection Coordination	OPA	8/11/2016	6/7/2018	10/1/2020	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	10/1/2020	An analysis to determine whether Protection Systems operate in the intended sequence during Faults.
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).
Real-time Assessment	Project 2007-06.2 Phase 2 of System Protection Coordination	RTA	8/11/2016		10/1/2020	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.)

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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.
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.

Retired Terms							
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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			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			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))
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.
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							
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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 (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 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.

Retired Terms							
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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.
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.

Retired Terms							
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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 NAEBS 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 Transfer Capabilities		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 predetermined 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.
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.

Retired Terms							
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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.

Retired Terms							
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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.
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.
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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
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.
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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
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.
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
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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
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.
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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
Remedial Action Scheme	Version 0 Reliability Standards	RAS	2/8/2005	3/16/2007		3/31/2017	See “Special Protection System”
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: $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$ Reporting ACE is calculated in the Western Interconnection as follows: $\text{Reporting ACE} = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$ 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.
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 Automatic Time Error Correction control mode: $ATEC = \frac{PI_{\text{Interchange}}}{(H - 1) \cdot H}$ • Y = B / BS. • H = Number of hours used to payback Primary Inadvertent Interchange energy. The value of H is set to 3.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
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 $(1-Y) * (II_{actual} - B * \Delta TE/6)$ 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: $\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t) * (TE_{offset})$ 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: $PII_{on/off\ peak} = \text{last period's } PII_{on/off\ peak} + PII_{hourly}$ All NERC Interconnections with multiple Balancing Authorities operate using the
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.
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.

Retired Terms							
Continent-wide Term	Link to Project Page	Acronym	BOT Adoption Date	FERC Approval Date	Effective Date	Inactive Date	Definition
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.
Transmission Customer	Version 0 Reliability Standards		2/8/2005	3/16/2007			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 responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Operator	Version 0 Reliability Standards	TOP	2/8/2005	3/16/2007			The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Owner	Version 0 Reliability Standards	TO	2/8/2005	3/16/2007			The entity that owns and maintains transmission facilities.
Transmission Planner	Version 0 Reliability Standards	TP	2/8/2005	3/16/2007			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 Service Provider	Version 0 Reliability Standards	TSP	2/8/2005	3/16/2007			The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Vegetation Inspection	Transmission Vegetation		2/7/2006	3/16/2007		3/20/2013	The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection	Project 2007-07 Transmission Vegetation Management		11/3/2011	3/21/2013		6/30/2014	The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission 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.

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			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: <i>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).</i>

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			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 Transfer Path	WECC Regional Standards Under Development		2/10/2009	3/17/2011			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			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		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			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
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 Vulnerability 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

Mandatory Reliability Standards Assessment Report No. 12

Appendix C-1

BC Hydro Feedback Survey Forms

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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.

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Hyperlinks to associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the revised version of the Standard and Mapping document)	Functional Applicability of FERC Approved Standard/Requirement(s)	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)	Compliance Lead(s)	Supporting Contact(s)	BC Hydro 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(\$)								BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
											IT Cost One Time (\$)	IT Cost Ongoing (\$)	PSEC Cost One Time (\$)	PSEC Cost Ongoing (\$)	TSTN Cost One Time (\$)	TSTN Cost Ongoing (\$)	GSTN Cost One Time (\$)	GSTN Cost Ongoing (\$)	
CIP-003.7.R1	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003.6 (See Assessment Report B)	7. Minor modification of requirement language to incorporate a policy for low impact BES systems into CIP-003.7.R1.2 (moved from CIP-003.5.R2) and addition of low impact code requirements for Transient Cyber Asset and Removable Media as well as CIP-03.6	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, issued April 18, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously approved initial compliance date for Reliability Standard CIP-003.6, other than the compliance date for Reliability Standard CIP-003.6, Requirement D2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	IT: Zhang, Yingqi (Primary Contact) GSTN: Davidoff, Jake TSTN: Savarian, Sara PSEC: Brian Hardcastle (Primary Contact)	IT: Wang, Philip (Secondary Contact) Hamed, Omid (Manager) GSTN: Kojic, Enisa (Primary Contact) Primer, Rob (Manager) TSTN: Ocong, Nathan (Primary Contact) Sylvir, Dave (Manager) Sach, Kelly (SME) PSEC: Ponto, Lloyd (Secondary Contact) Holland, Fawn (SFO - Primary Contact) Ferguson, Aaron (SFO - Primary Contact) Prestwich, Mark (SFO - Primary Contact) Brown, Jesse (SFO - Primary Contact) Britter, Richard (SFO - Manager)	BC Hydro has 115 transmission stations and 18 generation stations classified as low impact for which incremental protections will need to be afforded per the policy and plan requirements of CIP-003.7 (per Attachment 1, Sections 2, 3, and 5) Cross-BC Hydro program level activities and costs are included in the respective BC Hydro business group estimates for the following: 1. Program management resources and activities: Program Manager, business analyst and subject matter experts, solutions architect, pilot audit, project administration. Calculated at 18% of all other cost 2. Change management resources and activities – includes change management analyst, organizational designer, and on-going training software and management 3. Interest costs during construction – calculated at 4% GSTN and TSTN: Estimated Costs: \$3,948,000 (one-time) for Developing/implementing through site verification inventories of Cyber Assets and implementing an inventory labeling system. Development of and updates to existing process documents, engineering standards and work procedures. PSEC: \$718,000 (ongoing) annually for sustainment for Annual review of processes and standards (25% of initial costs), and Managing Cyber Asset changes, inclusive of maintaining up-to-date inventories. IT: Estimated Costs: \$107,000 (one-time) for Changes to compliance management system for asset inventory and work flow development \$107,000 (ongoing) annually for sustainment for Revisions/updates of corporate level policies and programs PSEC: Incremental activities and costs included as part of CIP-003.7.R2.	\$107,000	18,000	See CIP-003-7.R2 costs	See CIP-003-7.R2 costs	\$3,481,000	\$524,000	\$467,000	\$194,000	Follow the CIP-003.7 Implementation plan adopted by FERC in the U.S. with the following exceptions: First day of first calendar quarter, four years after BCUC adoption for Attachment 1 Section 2 (cyber security plan for physical security controls) and Section 3 (cyber security plan for electronic access controls) First day of first calendar quarter, two years after BCUC adoption for Attachment 1 Section 5 (cyber security plan for Transient Cyber Asset and Removable Media malicious code risk mitigation) Immediately after BCUC adoption for Attachment 1 Section 1 (cyber security awareness) and Section 4 (cyber security incident response).
			CIP-003.6 to CIP-003.7 Mapping Document																
CIP-003.7.R2	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003.6 (See Assessment Report B)	7. New requirements, major changes referencing security plans instead of CIP-0.003.6	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, issued April 18, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously approved initial compliance date for Reliability Standard CIP-003.6, other than the compliance date for Reliability Standard CIP-003.6, Requirement D2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	IT: Zhang, Yingqi (Primary Contact) GSTN: Davidoff, Jake TSTN: Savarian, Sara PSEC: Brian Hardcastle (Primary Contact)	IT: Wang, Philip (Secondary Contact) Hamed, Omid (Manager) GSTN: Kojic, Enisa (Primary Contact) Primer, Rob (Manager) TSTN: Ocong, Nathan (Primary Contact) Sylvir, Dave (Manager) Sach, Kelly (SME) PSEC: Ponto, Lloyd (Secondary Contact) Holland, Fawn (SFO - Primary Contact) Ferguson, Aaron (SFO - Primary Contact) Prestwich, Mark (SFO - Primary Contact) Brown, Jesse (SFO - Primary Contact) Britter, Richard (SFO - Manager)	BC Hydro has 115 transmission stations and 18 generation stations classified as low impact for which incremental protections will need to be afforded per the policy and plan requirements of CIP-003.7 (per Attachment 1, Sections 2, 3, and 5) Cross-BC Hydro program level activities and costs are embedded in the respective BC Hydro business group estimates for the following resources and activities: 1. Program management resources and activities: Program manager, business analyst, subject matter experts, solutions architect, pilot audit, project administration. Calculated at 18% of all other cost 2. Change management resources and activities – includes change management analyst, organizational designer, and on-going training software and management 3. Interest costs during construction – calculated at 4% Generation and Transmission Stations (GSTN and TSTN): Estimated Costs: \$10,964,000 (one-time) for Adding firewall panels to ~20 transmission stations, Adding telnet authentication to 110 transmission stations, Reviewing/implementing firewall access controls for 18 generation stations, and Development/verification of network diagrams for all 115 transmission stations and 18 generation stations. Physical Security (PSEC): Estimated Costs: \$3,981,000 (one-time) for Installation of badge card readers at physical zones (i.e. buildings and cabinets) containing low impact BES Cyber Assets, Rekeying baseline for restricted physical key access to physical zones containing low impact BES Cyber Assets, Implementation of physical key management cabinets to store and track restricted physical keys, Updates to physical security plan documentation, standard operating procedures for security personnel, and Rollout of training and awareness on updated processes and controls. Information Technology (IT): Estimated Costs: \$130,000 (one-time) for Physical Access Control System (PACS) workflow updates for managing access requests, inclusive of analysis, data migration, regression testing, etc. and creating new access permission levels. Process documentation updates. \$26,000 (ongoing) annually for sustainment for Ongoing support and management of PACS for access management/evacuation Reviews and updates of process documentation	130,000	26,000	9,981,000	3,089,000	\$10,045,000	\$1,903,000	\$819,000	\$108,000	Follow the CIP-003.7 Implementation plan adopted by FERC in the U.S. with the following exceptions: First day of first calendar quarter, four years after BCUC adoption for Attachment 1 Section 2 (cyber security plan for physical security controls) and Section 3 (cyber security plan for electronic access controls) First day of first calendar quarter, two years after BCUC adoption for Attachment 1 Section 5 (cyber security plan for Transient Cyber Asset and Removable Media malicious code risk mitigation) Immediately after BCUC adoption for Attachment 1 Section 1 (cyber security awareness) and Section 4 (cyber security incident response).
			CIP-003.6 to CIP-003.7 Mapping Document																
CIP-003.7.R3	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003.6 (See Assessment Report B)	7. No change to this requirement from previous version.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, issued April 18, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously approved initial compliance date for Reliability Standard CIP-003.6, other than the compliance date for Reliability Standard CIP-003.6, Requirement D2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	IT: Zhang, Yingqi (Primary Contact)	IT: Wang, Philip (Secondary Contact) Hamed, Omid (Manager)	IT: No incremental impacts anticipated.	0	0	N/A	N/A	N/A	N/A	N/A	N/A	Follow the CIP-003.7 Implementation plan adopted by FERC in the U.S. with the following exceptions: First day of first calendar quarter, four years after BCUC adoption for Attachment 1 Section 2 (cyber security plan for physical security controls) and Section 3 (cyber security plan for electronic access controls) First day of first calendar quarter, two years after BCUC adoption for Attachment 1 Section 5 (cyber security plan for Transient Cyber Asset and Removable Media malicious code risk mitigation) Immediately after BCUC adoption for Attachment 1 Section 1 (cyber security awareness) and Section 4 (cyber security incident response).
CIP-003.6 to CIP-003.7 Mapping Document																			
CIP-003.7.R4	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003.6 (See Assessment Report B)	7. No change to this requirement from previous version.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, issued April 18, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously approved initial compliance date for Reliability Standard CIP-003.6, other than the compliance date for Reliability Standard CIP-003.6, Requirement D2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	IT: Zhang, Yingqi (Primary Contact)	IT: Wang, Philip (Secondary Contact) Hamed, Omid (Manager)	IT: No incremental impacts anticipated.	0	0	N/A	N/A	N/A	N/A	N/A	N/A	Follow the CIP-003.7 Implementation plan adopted by FERC in the U.S. with the following exceptions: First day of first calendar quarter, four years after BCUC adoption for Attachment 1 Section 2 (cyber security plan for physical security controls) and Section 3 (cyber security plan for electronic access controls) First day of first calendar quarter, two years after BCUC adoption for Attachment 1 Section 5 (cyber security plan for Transient Cyber Asset and Removable Media malicious code risk mitigation) Immediately after BCUC adoption for Attachment 1 Section 1 (cyber security awareness) and Section 4 (cyber security incident response).

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FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and available RSWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Hyperlinks to associated Assessment Report feedback spreadsheet)	FERC Approved Revision (Hyperlinks to the revised version of the Standard and mapping document)	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 date if applicable)	BC Hydro Stakeholder Comments Organizational Activities and Reliability/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental New Costs Associated with Revision/Requirement, if any (\$)												BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									T&D Station/Line Planning and Ops Cost One Time (\$)	T&D Station/Line Planning and Ops Cost Ongoing (\$)	Reliability Coordinator Cost One Time (\$)	Reliability Coordinator Cost Ongoing (\$)	System Operations Cost One Time (\$)	System Operations Cost Ongoing (\$)	GEN Stations Asset Planning/Ops Cost One Time (\$)	GEN Stations Asset Planning/Ops Cost Ongoing (\$)	Engineering Cost One Time (\$)	Engineering Cost Ongoing (\$)	Security Cost One Time (\$)	Security Cost Ongoing (\$)	
BAL-002.3.R1	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002.3 (see Assessment Report 10)	2. New requirement added to R1 to (i) verify the BCUC of entity publishing its Contingency Reserve to initiate an operating emergency in accordance with its emergency operating plan as the reported Contingency Reserve that level below its Most Severe Single Contingency which exceeds conditions set forth in R2.3.2.2, and to provide the BCUC with R2.3.2.2 response and recovery time recovery time.	BA, RSG	Docket No. RD18-2-000, Issued September 26, 2018	26-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Need to coordinate with Northwest Power Pool (NWP) RSG, BC Hydro's BA function, and other RCs to develop communicating protocols and revise procedures. Estimated Costs: \$2,000 (one-time) to revise procedures and contribute to coordination efforts. System Operations: Need to coordinate with Northwest Power Pool RSG, BC Reliability Coordinator (RC) and other RCs to develop communicating protocols and revise procedures. Develop training to BC Hydro Generation Coordinators on "New R1". Estimated Costs: \$2,000 (one-time) to revise procedures and contribute to coordination efforts.	N/A	N/A	2,000	0	2,000	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is six months after BCUC adoption.
RSW			Mapping document not available																		
BAL-002.3.R2	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002.3 (see Assessment Report 10)	2. No changes to this requirement from previous version.	BA, RSG	Docket No. RD18-2-000, Issued September 26, 2018	26-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is six months after BCUC adoption.
RSW			Mapping document not available																		
BAL-002.3.R3	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002.3 (see Assessment Report 10)	2. No changes to this requirement from previous version.	BA, RSG	Docket No. RD18-2-000, Issued September 26, 2018	26-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is six months after BCUC adoption.
RSW			Mapping document not available																		
BAL-004.0 (retired standard)	Name: Time Error Correction Description: The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.	N/A - Retired standard. (see Assessment Report 2)	N/A - Retired standard	RC, BA	Docket No. RD17-1-000, Issued January 19, 2017	19-Jan-2017	No Implementation time required - Retired standard US Inactive Date: 1-April-2017	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	Retire immediately after BCUC approval.
BAL-004.WECC-3.R1	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. New or (b) for (a) (i) and (b) (ii) value of on and off peak. Accurately Primary Inadvertent Interchange.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: Minor revisions to Operating Orders and updates to training materials for System Operators. Estimated Costs: \$1,000 (one-time) for Operating Order and training material revisions; training related costs are negligible.	N/A	N/A	N/A	N/A	1,000	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R2	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R3	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R4	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R5	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R6	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R7	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
BAL-004.WECC-3.R8	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the Interconnection.	BAL-004.WECC-2 (see Assessment Report 7)	2. No changes to this requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the second calendar quarter after BCUC adoption.
EOP-004.4.R1	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004.3 (see Assessment Report 10)	4. Revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting. requirement R1, has been revised.	RC, BA, TO, TOP, GO, GCP, DP	Docket No. RM17-12-000, Order No. 642, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Need to align BC Hydro event reporting between its RC function and other functions (BA/TOTOP/GO/DP). Per the Guideline and Technical Basis, for any events experienced, BC Hydro would only submit one report on behalf of the company regardless of functional registration differences. Also, BC Hydro does not submit reports directly to NERC although the standard language requires it. BC Hydro submits to WECC. It would be helpful to address this in the adoption order to ensure all entities within BC are clear on how reports should be submitted. Estimated Costs: \$1,000 (one-time) to update RC documentation, consult with entities, and distribute final versions. \$500 / year in ongoing maintenance costs to perform annual reviews of RC documentation. System Operations: Minor updates to existing BC Hydro BA/TOTOP/GO/DP event reporting plan. Negligible costs. GEN Station Planning: Generation Operating Order needs to be updated. Negligible costs.	N/A	N/A	1,000 (inclusive of EOP-004.4 R2)	500 (inclusive of EOP-004.4 R2)	0	0	0	0	N/A	N/A	0	0	First day of the first calendar quarter that is twelve months after BCUC adoption.
RSW			EOP-004.3 to EOP-004.4 Mapping document																		
EOP-004.4.R2	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004.3 (see Assessment Report 10)	4. Minor revisions made to requirement R2 for clarity including a reference to Attachment 1, revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting. requirement R1 has been revised.	RC, BA, TO, TOP, GO, GCP, DP	Docket No. RM17-12-000, Order No. 642, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: See BC Hydro RC feedback per EOP-004.4 R1. System Operations: See BC Hydro System Operations feedback per EOP-004.4 R1. GEN Station Planning: Generation Operating Order needs to be updated. Negligible costs.	N/A	N/A	See EOP-004.4 R1	See EOP-004.4 R1	0	0	0	0	N/A	N/A	0	0	First day of the first calendar quarter that is twelve months after BCUC adoption.
RSW			EOP-004.3 to EOP-004.4 Mapping document																		

FERC Approved New/Revised/Updated Standard/Requirement (Hyperlinks to the Standard and available RSAW)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Hyperlinks to associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the revised version of the Standard and mapping document)	Functional Applicability of FERC Approved Standard/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)	BC Hydro 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 (\$)												BCUC Implementation Time (Press Alt+Enter to insert a carriage return in a cell)	
									T&D Station/Line Planning and Ops Cost One Time (\$)	T&D Station/Line Planning and Ops Cost Ongoing (\$)	Reliability Coordinator Cost One Time (\$)	Reliability Coordinator Cost Ongoing (\$)	System Operations Cost One Time (\$)	System Operations Cost Ongoing (\$)	GEN Stations Asset Planning/Ops Cost One Time (\$)	GEN Stations Asset Planning/Ops Cost Ongoing (\$)	Engineering Cost One Time (\$)	Engineering Cost Ongoing (\$)	Security Cost One Time (\$)	Security Cost Ongoing (\$)		
EOP-005-2 R1	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. Minor wording changes only.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-005-2 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R2	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. Changes to the specific roles and tasks within an approved restoration plan must now be communicated prior to the "effective date" of the plan, instead of the "implementation date".	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: Minor process impact to be implemented. Negligible costs.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R3	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	4. No changes to this requirement from previous version.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-005-2 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R4	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. The conditions for submission of revised restoration plan to the RC has been updated.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-005-2 standard as part of its application to the BCUC. System Operations: Minor process changes. Negligible impacts/costs.	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R5	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	2. Copy of the latest BC approved restoration plan must now be available in writing/backup control copies prior to the "effective date" of the plan instead of the "implementation date".	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R6	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	2. No material changes to this requirement from the previous version.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R7	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	2. This requirement is the same as EOP-005-2 R9. EOP-005-2 R7 has been added.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R8	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R10 with the exception of an additional update to the definition of "approved" and "approved date" within a T&D Area in the BSA EOP-005-2 R8 has been added.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R9	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	2. This requirement is the same as EOP-005-2 R11; no changes to the document.	TOP, TO, OP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R10	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R12; no changes to the document.	TOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-005-2 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R11	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R13; no changes to the document.	TOP, GOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	GEN Stations Asset Planning: Generation Operating Order needs to be updated to reflect the new references in EOP-005-3. Negligible costs. System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R12	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R14; no changes to the document.	GOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	GEN Stations Asset Planning: Generation Operating Order needs to be updated to reflect the new references in EOP-005-3. Negligible costs.	N/A	N/A	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R13	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R15; no changes to the document.	GOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	GEN Stations Asset Planning: Generation Operating Order needs to be updated to reflect the new references in EOP-005-3. Negligible costs.	N/A	N/A	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R14	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R16; no changes to the document.	GOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-005-2 standard as part of its application to the BCUC. GEN Stations Asset Planning: Generation Operating Order needs to be updated to reflect the new references in EOP-005-3. Negligible costs.	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			
EOP-005-3 R15	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (See Assessment Report 7)	3. This requirement is the same as EOP-005-2 R17; no changes to the document.	GOP	Docket No. RM17-12-000, Order No. 669, Issued January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	GEN Stations Asset Planning: Generation Operating Order needs to be updated to reflect the new references in EOP-005-3. Negligible costs.	N/A	N/A	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.	
BSAW			EOP-005-2 to EOP-005-3 Mapping document																			

FERC Approved New/Revised/Updated Standard/Requirement (Hyperlinks to the Standard are available.)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Hyperlinks to associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the revised version of the Standard and mapping document)	Functional Applicability of FERC Approved Standard/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)	BC Hydro 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 (\$)												BCUC Implementation Time (Press Alt+Enter to insert a carriage return in a cell)
									T&D Station/Line Planning and Ops Cost One Time (\$)	T&D Station/Line Planning and Ops Cost Ongoing (\$)	Reliability Coordinator Cost One Time (\$)	Reliability Coordinator Cost Ongoing (\$)	System Operations Cost One Time (\$)	System Operations Cost Ongoing (\$)	GEN Stations Asset Planning/Ops Cost One Time (\$)	GEN Stations Asset Planning/Ops Cost Ongoing (\$)	Engineering Cost One Time (\$)	Engineering Cost Ongoing (\$)	Security Cost One Time (\$)	Security Cost Ongoing (\$)	
EOP-005.3 R16	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005.2 (See Assessment Report 7)	3. This requirement is the same as EOP-005.2 R16, no material changes to the requirement.	RCOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-005-2 standard as part of its application to the BCUC. GEN Stations Asset Planning: Generation Operating Order needs to be updated to reflect the new references in EOP-005-3. Negligible costs.	N/A	N/A	0	0	N/A	N/A	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twelve months after BCUC adoption.
BSAW			EOP-005.2 to EOP-005.3 Mapping document																		
EOP-006.3 R1	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. Retirement of EOP-006.2 Parts R1.2, R1.3, R1.4.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Minimal impact due to retirement of requirements, system restoration coordination plans will reflect changes. Negligible costs.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R2	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. No changes to this requirement from previous version.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-006-2 standard as part of its application to the BCUC.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R3	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. No changes to this requirement from previous version.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-006-2 standard as part of its application to the BCUC.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R4	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. New requires RC to provide written notification of any conflicts, documented details to review of, responses to, etc, restoration plan within 60 calendar days of request.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Documentation will need to reflect completion of review of other RC restoration plans within 60 days. Estimated Costs: \$500 (one-time) and \$500 (ongoing) for any edits to other RC restoration plans between annual reviews and the 60 day submission requirement.	N/A	N/A	500 (inclusive of EOP-006-3 RS and RE)	500 (inclusive of EOP-006-3 RS and RE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R5	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. Clarifies that the RC is to provide notification to the TOP of approval or disapproval of restoration plans.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Documentation will require minimal updates to align with changed language.	N/A	N/A	See EOP-006-3 R4	See EOP-006-3 R4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R6	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. Copy of the latest RC's restoration plan must now be available in primary/back-up control room prior to the "effective date" of the plan release of the restoration plan.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Documentation will require minimal updates to align with changed language.	N/A	N/A	See EOP-006-3 R4	See EOP-006-3 R4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R7	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. This requirement is the same as EOP-006.2 R9. No material changes to the requirement. EOP-006.2 R7 has been retired.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-006-2 standard as part of its application to the BCUC.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R8	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006.2 (See Assessment Report 7)	3. This requirement is the same as EOP-006.2 R10, no material changes to the requirement. EOP-006.4 R8 has been retired.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-006-2 standard as part of its application to the BCUC.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.2 to EOP-006.3 Mapping document																		
EOP-006.3 R1	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-006.1 (See Assessment Report 7)	2. B1 eliminated timing requirement to restore the primary control centre functionality in the current Operating Plan, restored primary data exchange capabilities for protective asset phase "data communications" which is consistent with IEC TOP standard	RC, TOP, BA	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Minor procedure updates to align language with revised standard. Negligible costs. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.1 to EOP-006.2 Mapping document																		
EOP-006.3 R2	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-006.1 (See Assessment Report 7)	2. No changes to this requirement from previous version.	RC, TOP, BA	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-006-1 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.1 to EOP-006.2 Mapping document																		
EOP-006.3 R3	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-006.1 (See Assessment Report 7)	2. B3 revised "depend out to 'available bc'" to clarify the intent of having the backup control center to meet compliance with Reliability Standards.	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: Minor procedural updates to align with language of revised standard. Negligible costs.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.1 to EOP-006.2 Mapping document																		
EOP-006.3 R4	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-006.1 (See Assessment Report 7)	2. B4 revised "depend out to 'available bc'" to clarify the intent of having the backup control center to meet compliance with Reliability Standards.	BA, TOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26-May-2018 (Following available regulatory approval) US Enforcement Date: 01-Apr-2019	Implementation Time: First day of the first calendar quarter that is twelve months following available regulatory approval. US Enforcement Date: 01-Apr-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.
BSAW			EOP-006.1 to EOP-006.2 Mapping document																		

FERC Approved New/Revised/Updated Standard/Requirement (Hyperlinks to the Standard and available RS&W)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Hyperlinks to associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the revised version of the Standard and mapping document)	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)	BC Hydro 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 (\$)												BCUC Implementation Time (Press Alt+Enter to insert a carriage return in a cell)	
									T&D Station/Line Planning and Ops Cost One Time (\$)	T&D Station/Line Planning and Ops Cost Ongoing (\$)	Reliability Coordinator Cost One Time (\$)	Reliability Coordinator Cost Ongoing (\$)	System Operations Cost One Time (\$)	System Operations Cost Ongoing (\$)	GEN Stations Asset Planning/Ops Cost One Time (\$)	GEN Stations Asset Planning/Ops Cost Ongoing (\$)	Engineering Cost One Time (\$)	Engineering Cost Ongoing (\$)	Security Cost One Time (\$)	Security Cost Ongoing (\$)		
EOP-008-2-06 RS&W	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 Data Assessment Report 1	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. RM-18-004, January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-008-1 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.	
EOP-008-2-06 RS&W	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 Data Assessment Report 1	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. RM-18-004, January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-008-1 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.	
EOP-008-2-07 RS&W	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 Data Assessment Report 1	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA and TOP	Docket No. RM17-12-000, Order No. RM-18-004, January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-008-1 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.	
EOP-008-2-08 RS&W	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 Data Assessment Report 1	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. RM-18-004, January 18, 2018	26-May-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding EOP-008-1 standard as part of its application to the BCUC. System Operations: No incremental impacts anticipated.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter, twelve months after BCUC adoption.	
FAC-001-WECC-2-R1 RS&W	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP) and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-001-WECC-1 Data Assessment Report 1	2. FAC-001-WECC-1 Attachment 1 "Transmission Line and Station Maintenance" details have been revised to FAC-001-WECC-2 Attachment 2 and makes modest changes to the mandatory minimum requirements for "Transmission Maintenance and Inspection Plan (TMIP)" including key sections: Maintenance Methodology and Technology - the attachment E- Major WECC Transfer Paths in the BES is also revised in the updated standard. Requirement E1 has been modified to align with the above change, and requires TO to have a TMIP according to Attachment A.	TO	Docket No. RM18-6-000, issued May 23, 2018	30-May-18	Implementation Time: First day of the first quarter following applicable regulatory approval. US Enforcement Date: 01-Jul-2019	T&D Line and Stations Planning: Minor updates to be made to the TMIP to reflect revised standard. Negligible costs.	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.	
FAC-001-WECC-2-R2 RS&W	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP) and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-001-WECC-1 Data Assessment Report 1	2. FAC-001-WECC-1 R1-1 was revised to FAC-001-WECC-2 R2 with modifications to add clarity. i.e. when TMIP update has occurred, it was changed to reflect the changes to E3. i.e. FAC-001-WECC-1 R2 has been added.	TO	Docket No. RM18-6-000, issued May 23, 2018	30-May-18	Implementation Time: First day of the first quarter following applicable regulatory approval. US Enforcement Date: 01-Jul-2019	T&D Line and Stations Planning: Need to institute controls to ensure reviews of TMIP occur at least every 12 calendar months instead of annually (once per calendar year). Negligible costs.	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.	
FAC-001-WECC-2-R3 RS&W	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP) and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-001-WECC-1 Data Assessment Report 1	2. No major change to this requirement, language modification - i.e. "documented and in accordance with the TMIP".	TO	Docket No. RM18-6-000, issued May 23, 2018	30-May-18	Implementation Time: First day of the first quarter following applicable regulatory approval. US Enforcement Date: 01-Jul-2019	T&D Line and Stations Planning: No incremental impacts anticipated.	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first quarter following BCUC adoption.	
PER-003-2-R1 Draft RS&W	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 Data Assessment Report 1	2. No material change to this requirement apart from a footnote reference to clarify that the reference to NERC Reliability Operator certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification.	RC	Docket No. RM18-6-000, issued November 21, 2018	21-Nov-18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval. US Enforcement Date: 01-Jul-2019	Reliability Coordinator: No incremental impacts anticipated beyond what is already planned by the BC Hydro Reliability Coordinator function for the preceding PER-003-1 and PER-004-2 standards as part of its application to the BCUC.	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first quarter that is six months following BCUC adoption.	
PER-003-2-R2 Draft RS&W	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 Data Assessment Report 1	2. No material change to this requirement apart from a footnote reference to clarify that the reference to NERC Reliability Operator certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification.	TOP	Docket No. RM18-6-000, issued November 21, 2018	21-Nov-18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval. US Enforcement Date: 01-Jul-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first quarter that is six months following BCUC adoption.	
PER-003-2-R3 Draft RS&W	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 Data Assessment Report 1	2. No material change to this requirement apart from a footnote reference to clarify that the reference to NERC Reliability Operator certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification.	BA	Docket No. RM18-6-000, issued November 21, 2018	21-Nov-18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval. US Enforcement Date: 01-Jul-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first quarter that is six months following BCUC adoption.	
PER-004-1-R1 Draft RS&W	Name: Specific Training for Personnel Description: To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.	PRC-001-1-101 Data Assessment Report 1	1. New standard PER-004-1 R1 replaces PRC-001-1-101 (E1) also the referenced term Special Protection System (SPS) has been replaced with Protective Action Scheme (PAS).	GOP	Docket No. RM16-22-000, Order No. RM-17-018, issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	GEN Stations Asset Planning/GEN Stations First Operations/System Operations: Training material will need to be reviewed and minor updates made. Negligible changes and costs as PER-004-1 training content is largely covered under existing training at BC Hydro. Generation Operating Orders and inventory management system business rules will need to be reviewed and updated. Negligible costs.	N/A	N/A	N/A	N/A	0	0	0	0	N/A	N/A	N/A	N/A	First day of the first calendar quarter that is twenty-four months after BCUC adoption.	
PRC-005-2-R1 RS&W	Name: Generator Relay Loadability Description: To set load-responsive protective relays associated with generation facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	PRC-005-1 Data Assessment Report 1	2. Provides clarification for specific Facility applications and load-responsive protective relays. LV protection devices that do not have load-responsive settings are included in the study settings analysis. Increased alternative loadability capacity for Phase 1 settings in planned power transfer scenarios, determined by the bus, based on 1% of the bus rating, with the intent of the standard for relays to "not trip" and provided clarity on the compliance date.	GO, TO, DP	Docket No. RM18-4-000, issued July 2, 2018	2-May-2018	Implementation Time: First day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard. Initial compliance is as follows: Except for new loadability evaluation criteria options Sa, Sb, 2a, 2b, 2c, 2d, 2e, 11, 12a, 12b, 12c, 12d, and 12e, if the functional entity determines that replacement or removal of load-responsive protective relays is not necessary, later of October 1, 2021 or 36 months after the effective date. For Options Sa, Sb, 2a, 2b, 2c, 2d, 2e, 11, 12a, 12b, 12c, 12d, and 12e, if the functional entity determines that replacement or removal of load-responsive protective relays is not necessary, later of October 1, 2021 or 36 months after the effective date.	Engineering: Relay loadability checking of 29 BC Hydro transmission lines connected to BC Hydro generation stations will need to be performed to align with PRC-005-2 revisions. Estimated Costs: \$20,000 (one-time) for initial relay loadability checks, and \$10,000 (ongoing) on an annual basis for ongoing maintenance verification.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	20,000	10,000	N/A	N/A	First day of the first calendar quarter after BCUC adoption. Phased in compliance dates for initial performance to follow similar timeframes as the FERC approved NERC implementation plan via a BCUC approved implementation plan.	

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and available HSAs/Hs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Hyperlinks to associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the revised version of the Standard and mapping document)	Functional Applicability of FERC Approved Standard/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)	BC Hydro 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 (\$)												BCUC Implementation Time (Press Alt+Enter to insert a carriage return in a cell)
									T&D Station/Line Planning and Ops Cost One Time (\$)	T&D Station/Line Planning and Ops Cost Ongoing (\$)	Reliability Coordinator Cost One Time (\$)	Reliability Coordinator Cost Ongoing (\$)	System Operations Cost One Time (\$)	System Operations Cost Ongoing (\$)	GEN Station Asset Planning/Ops Cost One Time (\$)	GEN Station Asset Planning/Ops Cost Ongoing (\$)	Engineering Cost One Time (\$)	Engineering Cost Ongoing (\$)	Security Cost One Time (\$)	Security Cost Ongoing (\$)	
PSC-027.1.B1	Name: Coordination of Protection Systems for Performance During Faults Description: To maintain the coordination of Protection Systems related to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PSC-001.1.101 (See Assessment Report 9)	1. New standard. Incorporates reliability objectives of PSC-001.1.101 (B) and (C), clarifies the coordination aspects, applicability, changed to (C) TO and (C) P, and includes additional requirements. PSC-027.1.B1 maintains an ability to establish a process for deviations and corrections. Provides System settings for BES Elements to operate in the intended sequence. (6/26/2018)	TO, GO, DP	Docket No. 2016-07-000, Order No. 847, issued June 7, 2016	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Engineering: Need to establish a process for developing new and revised Protection System settings for BES elements such that the protection systems operate in the intended sequence during faults. Estimated Costs: -\$600,000 one-time to review and update short-circuit model data for BES Elements (applicable BES line, transformer, and generator, Fault currents, configuration of the actual System, and report of data base review, etc.) -\$200,000 one-time to review developed Protection System settings (i.e., peer review, automated checking programs, developed review procedures, and report of protection system review) -\$100,000 one-time to coordinate Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Provide the proposed Protection System settings to the owners of the electrically joined Facilities; Request to owners of the electrically joined Facilities, verify that identified coordination issues) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation; Communicate with the other owners of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances, etc.) -\$50,000 one-time to establish processes and evidence. -\$100,000/year in ongoing costs for sustainment.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1,000,000	100,000	N/A	N/A	First day of the first calendar quarter that is twenty-four months after BCUC adoption. Initial Performance of Requirement R2: For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PSC-027.1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PSC-027.1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PSC-027.1.	
PSC-027.1.B2	Name: Coordination of Protection Systems for Performance During Faults Description: To maintain the coordination of Protection Systems related to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PSC-001.1.101 (See Assessment Report 9)	1. New standard. Incorporates reliability objectives of PSC-001.1.101 (B) and (C), clarifies the coordination aspects, applicability, changed to (C) TO and (C) P, and includes additional requirements. PSC-027.1.B2 maintains an ability to establish a process for deviations and corrections. Provides System settings for BES Elements to operate in the intended sequence. (6/26/2018)	TO, GO, DP	Docket No. 2016-07-000, Order No. 847, issued June 7, 2016	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Engineering: As indicated in the standard, three study options are available. Report of the study dependent on the option chosen will need to be developed. Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values within three phases or phase to ground) at a bus to which the BES Element is connected, at a time interval not to exceed six-calendar years; or, Option 3: Use a combination of the above. Estimated Costs: \$200,000 one-time for initial compliance and \$200,000 ongoing for sustainment every 6 years = ~\$33,333/year.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	200,000	200,000 / 6 years	N/A	N/A	First day of the first calendar quarter that is twenty-four months after BCUC adoption. Initial Performance of Requirement R2: For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PSC-027.1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PSC-027.1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PSC-027.1.	
PSC-027.1.B3	Name: Coordination of Protection Systems for Performance During Faults Description: To maintain the coordination of Protection Systems related to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.	PSC-001.1.101 (See Assessment Report 9)	1. New standard. Incorporates reliability objectives of PSC-001.1.101 (B) and (C), clarifies the coordination aspects, applicability, changed to (C) TO and (C) P, and includes additional requirements. PSC-027.1.B3 provides that an entity utilize the process established in accordance with PSC-027.1.B1.	TO, GO, DP	Docket No. 2016-07-000, Order No. 847, issued June 7, 2016	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Engineering: Utilize the process established in Requirement R1 to develop new and revised Protection System settings for BES Elements and conduct internal annual audit of compliance for sustainment (internal controls). Estimated cost: \$50,000 (one-time) for initial compliance and \$50,000 (ongoing) annually in sustainment.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	50,000	50,000	N/A	N/A	First day of the first calendar quarter that is twenty-four months after BCUC adoption. Initial Performance of Requirement R2: For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PSC-027.1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PSC-027.1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PSC-027.1.	
VAR-001.5.B1	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. No changes to requirement, minor format changes to standard.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.B2	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. No changes to requirement, minor format changes to standard.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.B3	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. No changes to requirement, minor format changes to standard.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.B6	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. No changes to requirement, minor format changes to standard.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.E.A.10	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. No changes to requirement, measures were updated and indicated, replacing current NERC conventions, replacing "shall" with "will" and other minor format changes.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.E.A.14	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. In E.A.14 "Xref" was changed to "Xref", measures were updated and indicated, replacing current NERC conventions, replacing "shall" with "will" and other minor format changes.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.E.A.15	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. This requirement is the same as VAR-001.4.2 E.A.16 (no changes to requirement), however, VAR-001.4.2 E.A.15 and associated elements were reworded to make the text consistent with VAR-001.4.1, consistent with the following Network Voltage Schedule, Requirement R2, Part 2.2 as a result of related rule changes, replacing word "shall" with "will" and other minor format changes.	GOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.E.A.16	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. This requirement is the same as VAR-001.4.2 E.A.17 (no changes to requirement), however, measures were updated and indicated, replacing current NERC conventions, replacing "shall" with "will" and other minor format changes.	TOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.5.E.A.17	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001.4.2 (See Assessment Report 11)	6. This requirement is the same as VAR-001.4.2 E.A.16 (no change to requirement), however, measures were updated and indicated, replacing current NERC conventions, replacing "shall" with "will" and other minor format changes.	GOP	Docket No. 2016-08-000, issued October 15, 2016	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	System Operations: No incremental impacts anticipated.	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	N/A	N/A	First day of the first calendar quarter after BCUC adoption.
VAR-001.6.E.C.C.2 - retired standard	Name: Automatic Voltage Regulators (AVR) Description: To ensure that Automatic Voltage Regulators on synchronous generators and condensers shall be kept in service and controlling voltage.	N/A Retired standard. (See Assessment Report 9)	N/A Retired standard	GO, TOP	Docket No. 2016-1-000, issued September 8, 2016	8-Sep-2018	No Implementation time required: Retired standard US Inactive Date: Sep-5-2018	System Operations: No incremental impacts anticipated.	0	0	N/A	N/A	N/A	N/A	0	0	N/A	N/A	N/A	N/A	Retire standard immediately after BCUC approval.

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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.

FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 6, 2017 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 06, 2017 Glossary of Terms	Current BCUC Adopted Definition from October 06, 2017 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 (\$)	
Operational Planning Analysis *Glossary of term is specific to the new PER-006-1 standard in addition to currently adopted IRO-008-1 standard.	OPA	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.)	Operational Planning Analysis (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020	See comments associated with PER-006-1 standard.	See costs associated with PER-006-1 standard.	See costs associated with PER-006-1 standard.	Coincide with effective date of PER-006-1 standard after BCUC adoption.
Protection System Coordination Study *Glossary of term is specific to new the PRC-027-1 standard.		An analysis to determine whether Protection Systems operate in the intended sequence during Faults.	New	N/A	7-Jun-2018	1-Oct-2020	See comments associated with PRC-027-1 standard.	See costs associated with PRC-027-1 standard.	See costs associated with PRC-027-1 standard.	Coincide with effective date of PRC-027-1 standard after BCUC adoption.
Real-time Assessment *Glossary of term is specific to the new PER-006-1 standard in addition to currently adopted IRO-008-1 standard.	RTA	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.)	Real-time Assessment (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020	See comments associated with PER-006-1 standard.	See costs associated with PER-006-1 standard.	See costs associated with PER-006-1 standard.	Coincide with effective date of PER-006-1 standard after BCUC adoption.
Removable Media *Glossary of term is specific to revised CIP-003-7 standard in addition to currently adopted CIP-010-2 standard.		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.	Removable Media (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020	See comments associated with CIP-003-7 standard.	See costs associated with CIP-003-7 standard.	See costs associated with CIP-003-7 standard.	Coincide with effective date of CIP-003-7 standard after BCUC adoption.
Transient Cyber Asset *Glossary of term is specific to revised CIP-003-7 standard in addition to currently adopted CIP-010-2 standard.	TCA	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.	Transient Cyber Asset (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020	See comments associated with CIP-003-7 standard.	See costs associated with CIP-003-7 standard.	See costs associated with CIP-003-7 standard.	Coincide with effective date of CIP-003-7 standard after BCUC adoption.

Mandatory Reliability Standards Assessment Report No. 12

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>.

NOTE: The 2 new, 10 revised, and 2 retired Standards have been broken out into their requirements to enable stakeholders to provide detailed comments per requirement.

Complete the **CIP Stnds Feedback** and **OPS Stnds Feedback** (the yellow tabs), 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 I):** 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 J and K),**
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 I**. 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.

- d. **BCUC Implementation Time (Column L):**
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

INSTRUCTIONS FOR EXTERNAL STAKEHOLDERS

To Registered Entities – British Columbia Mandatory Reliability Standards Program,

Please review the revised NERC Glossary of Terms (July 3, 2018) 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 **Glossary Feedback Survey Form** (the red tab), and for each Term assessed, please complete the following fields:

- a. Insert the name and applicable functions of your registered entity at the top of the **Glossary Feedback Survey Form** Worksheet as indicated by the **red text** in **Row 2**.
- b. **Stakeholder Comments (Column H)**: Please provide a high-level list of activities required by your entity to mitigate/eliminate impacts based on the revised or new Term's definitions.
Please also indicate what high-level incremental activities or new activities need to be completed in order to become compliant.
- c. **The Estimated Incremental Cost Associated with Revised/New Term/Definition (Columns I and J)**, if any associated with:
 - a revision to a Term/Definition compared to the BCUC adopted version; or
 - the adoption of a new Term/Definition.

Please indicate which costs are one-time versus ongoing, and identify the assumptions associated with each estimate.
BC Hydro will use this information to develop recommendations to the BCUC regarding the potential impacts of each Term on registered entities for inclusion in the Report.

d. BCUC Implementation Time (Column K):

Please include an assessment of the amount of time your organization would reasonably require to come into compliance with the Glossary Term and 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 each Glossary Term and definition for inclusion in the Report.

Regards,

BC Hydro Reliability Compliance Department
BCHydroReliabilityStandards@bchydro.com

Mandatory Reliability Standards Assessment Report No. 12

Appendix C-3 External Stakeholder Feedback

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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.

CPPR, CPCD, CPPAD (DP, DPULS Only)

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the Mapping document)	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 (\$)		BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									One Time (\$)	Ongoing (\$)	
CIP-003-7 R1	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - Minor modification of requirement language to incorporate a policy for low impact BES systems into CIP-003-7 R1.2 (moved from CIP-003-5 R2) and addition of low impact policy requirements for Transient Cyber Assets and Removable Media as well as CIP Exceptional Circumstances. CIP-003-7 R1.1 and subparts have been moved from CIP-003-5 R1.1 to R1.9 and remain specific to high impact and medium impact policies.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	Significant revision of cyber policies required. New requirements for testing and verification triggered by mandatory participation in BC Hydro's RAS and SPS. May require installation of new hardware and software.	\$50,000	\$20,000	One year after Commission approval
			No mapping document available.								
CIP-003-7 R2	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - minor modifications to remove ambiguous language.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	Significant revision of cyber policies required. New requirements for testing and verification triggered by mandatory participation in BC Hydro's RAS and SPS. May require installation of new hardware and software. Associated with CIP-003-7 R1.			1 year after Commission approval
			CIP-003-5 to CIP-003-7 Mapping Document								
CIP-003-7 R3	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - No change to this requirement from previous version.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	No Change			
			CIP-003-5 to CIP-003-7 Mapping Document								
CIP-003-7 R4	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - No change to this requirement from previous version.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	No Change			
			CIP-003-5 to CIP-003-7 Mapping Document								

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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.

CPPR, CPD, CPPAD (DP, DPULS Only)

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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 (\$) (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 (\$)	
BAL-002-3 R1	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002-2 (see Assessment Report 10)	2 - New requirement added to R1 to (i) notify the RC if entity is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single Contingency which prevents compliance with recovery of Reporting ACE, and (ii) provide the RC with an ACE recovery plan, including target recovery time. Mapping document: not available	BA, RSG	Docket No. RD18-7-000, Issued September 26, 2018	26-Sep-2019	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
BAL-002-3 R2	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002-2 (see Assessment Report 10)	2 - No changes to this requirement from previous version. Mapping document: not available	BA, RSG	Docket No. RD18-7-000, Issued September 26, 2018	26-Sep-2019	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
BAL-002-3 R3	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002-2 (see Assessment Report 10)	2 - No changes to this requirement from previous version. Mapping document: not available	BA, RSG	Docket No. RD18-7-000, Issued September 26, 2018	26-Sep-2019	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
BAL-004-0 (retire standard)	Name: Time Error Correction Description: The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the interconnection	N/A - Retired standard (see Assessment Report 1)	N/A - Retired standard	RC, BA	Docket No. RD17-1-000, Issued January 18, 2017	18-Jan-2017	No Implementation time required: Retired standard US Inactive Date: 1-April-2017	Not Applicable			
BAL-004-WECC-3 R1	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection	BAL-004-WECC-2 (see Assessment Report 7)	2 - New criteria for month-end absolute value of on and off peak Accumulated Primary Inadvertent Interchange. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
BAL-004-WECC-3 R2	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
BAL-004-WECC-3 R3	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
BAL-004-WECC-3 R4	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
BAL-004-WECC-3 R5	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
BAL-004-WECC-3 R6	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
BAL-004-WECC-3 R7	Name: Automatic Time Error Correction Description: To maintain Interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version. Mapping document not available	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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 Rulings)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
BAL-004-WECC-3 BA	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PI) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RM19-2-000, Issued May 26, 2018	26 May 2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	Not Applicable			
			Mapping document not available								
EOP-004-4 R1	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004-3 (see Assessment Report 10)	4 - Revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting; requirement R3 has been retired.	RC, BA, TO, TOP, GO, GOP, DP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No incremental changes expected.			
			EOP-004-3 to EOP-004-4 Mapping document								
EOP-004-4 R2	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004-3 (see Assessment Report 10)	4 - Minor revisions made to requirement R2 for clarity including a reference to Attachment 1; revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting; requirement R3 has been retired.	RC, BA, TO, TOP, GO, GOP, DP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No incremental changes expected.			
			EOP-004-3 to EOP-004-4 Mapping document								
EOP-005-3 R1	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - Minor wording changes only.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R2	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - Changes to the specific roles and tasks within an approved restoration plan must now be communicated prior to the "effective date" of the plan instead of the "implementation date".	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R3	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - No changes to this requirement from previous version.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R4	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - The conditions for submission of revised restoration plan to the RC has been updated.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R6	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - Copy of the latest RC approved restoration plan must now be available in primary/backup control rooms prior to the "effective date" of the plan instead of the "implementation date".	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R6	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - No material changes to this requirement from the previous version.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R7	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R6; EOP-005-2 R7 has been retired.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R8	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R10 with the exception of an additional training requirement on transition of Demand and resource balance within a TOP's area to the BA; EOP-005-2 R8 has been retired.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R9	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R11; no changes to the requirement.	TOP, TO, DP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No incremental changes expected.			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R10	Name: System Restoration from Blackstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R12; no changes to the requirement.	TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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 Rulings)	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/Subsafety Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
EOP-005-3 R11	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R13; no changes to the requirement.	TOP, GOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R12	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R14; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R13	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R15; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R14	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R16; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R15	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R17; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-3 R16	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-005-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-005-2 R18; no material changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-006-3 R1	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - Retirement of EOP-006-2 Parts R1.2, R1.3, R1.4.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R2	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - No changes to this requirement from previous version.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R3	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - No changes to this requirement from previous version.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R4	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - Now requires RC to provide written notification of any conflicts discovered during the review of neighbouring RC's restoration plan within 60 calendar days of receipt.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R5	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - Clarifies that the RC is to provide notification to the TOP of approval or disapproval of restoration plans.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R6	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - Copy of the latest RC's restoration plan must now be available in primary/backstop control rooms prior to the "effective date" of the plan instead of the "implementation date".	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R7	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-006-2 R6; No material changes to the requirement. EOP-006-2 R7 has been retired.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								
EOP-006-3 R8	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3 - This requirement is the same as EOP-006-2 R10; no material changes to the requirement. EOP-006-2 R8 has been retired.	RC	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months, following applicable regulatory approval. US Enforcement Date: 01-Apr-2019.	Not Applicable			
			EOP-006-2 to EOP-006-3 Mapping document								

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	Functional Applicability of FERC Approved Standard/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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
EOP-008-2 R1	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC, TOP, BA	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R2	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC, TOP, BA	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R3	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R4	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	BA, TOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R5	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R6	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R7	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC, BA and TOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
EOP-008-2 R8	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 849, issued January 18, 2018	26 Mar 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Not Applicable			
FAC-501-WECC-2 R1	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP), and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-501-WECC-1 (see Assessment Report 5)		TO	Docket No. RD18-5-000, issued May 30, 2018	30 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval. US Enforcement Date: 01-Jul-2018	Not Applicable			
FAC-501-WECC-2 R2	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP), and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-501-WECC-1 (see Assessment Report 5)		TO	Docket No. RD18-5-000, issued May 30, 2018	30 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval. US Enforcement Date: 01-Jul-2018	Not Applicable			
FAC-501-WECC-2 R3	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP), and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-501-WECC-1 (see Assessment Report 5)		TO	Docket No. RD18-5-000, issued May 30, 2018	30 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval. US Enforcement Date: 01-Jul-2018	Not Applicable			
PER-006-1 R1	Name: Specific Training for Personnel Description: To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.	PRC-001-1.1(i) (see Assessment Report 9)	PRC-001-1(i) to PER-006-1 Mapping Document	GOP	Docket No. RM16-22-000, Order No. issued June 7, 2018	13 Aug 2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Not Applicable			
PRC-025-2 R1	Name: Generator Relay Loadability Description: To set load-responsive protective relays associated with generation facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	PRC-025-1 (see Assessment Report 8)		GO, TO, DP	Docket No. RD18-4-000, Issue Date: May 2, 2018	2 May 2018	Implementation Time: First day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard. Initial compliance is as follows: Exempt for relay loadability evaluation criteria options 3a, 3b, 3c, 3d, 3e, 3f, 3g, 3h, 3i, 3j, 3k, 3l, 3m, 3n, 3o, 3p, 3q, 3r, 3s, 3t, 3u, 3v, 3w, 3x, 3y, 3z, 3aa, 3ab, 3ac, 3ad, 3ae, 3af, 3ag, 3ah, 3ai, 3aj, 3ak, 3al, 3am, 3an, 3ao, 3ap, 3aq, 3ar, 3as, 3at, 3au, 3av, 3aw, 3ax, 3ay, 3az, 3ba, 3bb, 3bc, 3bd, 3be, 3bf, 3bg, 3bh, 3bi, 3bj, 3bk, 3bl, 3bm, 3bn, 3bo, 3bp, 3bq, 3br, 3bs, 3bt, 3bu, 3bv, 3bw, 3bx, 3by, 3bz, 3ca, 3cb, 3cc, 3cd, 3ce, 3cf, 3cg, 3ch, 3ci, 3cj, 3ck, 3cl, 3cm, 3cn, 3co, 3cp, 3cq, 3cr, 3cs, 3ct, 3cu, 3cv, 3cw, 3cx, 3cy, 3cz, 3da, 3db, 3dc, 3dd, 3de, 3df, 3dg, 3dh, 3di, 3dj, 3dk, 3dl, 3dm, 3dn, 3do, 3dp, 3dq, 3dr, 3ds, 3dt, 3du, 3dv, 3dw, 3dx, 3dy, 3dz, 3ea, 3eb, 3ec, 3ed, 3ee, 3ef, 3eg, 3eh, 3ei, 3ej, 3ek, 3el, 3em, 3en, 3eo, 3ep, 3eq, 3er, 3es, 3et, 3eu, 3ev, 3ew, 3ex, 3ey, 3ez, 3fa, 3fb, 3fc, 3fd, 3fe, 3ff, 3fg, 3fh, 3fi, 3fj, 3fk, 3fl, 3fm, 3fn, 3fo, 3fp, 3fq, 3fr, 3fs, 3ft, 3fu, 3fv, 3fw, 3fx, 3fy, 3fz, 3ga, 3gb, 3gc, 3gd, 3ge, 3gf, 3gg, 3gh, 3gi, 3gj, 3gk, 3gl, 3gm, 3gn, 3go, 3gp, 3gq, 3gr, 3gs, 3gt, 3gu, 3gv, 3gw, 3gx, 3gy, 3gz, 3ha, 3hb, 3hc, 3hd, 3he, 3hf, 3hg, 3hi, 3hj, 3hk, 3hl, 3hm, 3hn, 3ho, 3hp, 3hq, 3hr, 3hs, 3ht, 3hu, 3hv, 3hw, 3hx, 3hy, 3hz, 3ia, 3ib, 3ic, 3id, 3ie, 3if, 3ig, 3ih, 3ii, 3ij, 3ik, 3il, 3im, 3in, 3io, 3ip, 3iq, 3ir, 3is, 3it, 3iu, 3iv, 3iw, 3ix, 3iy, 3iz, 3ja, 3jb, 3jc, 3jd, 3je, 3jf, 3jg, 3jh, 3ji, 3jj, 3jk, 3jl, 3jm, 3jn, 3jo, 3jp, 3jq, 3jr, 3js, 3jt, 3ju, 3jv, 3jw, 3jx, 3jy, 3jz, 3ka, 3kb, 3kc, 3kd, 3ke, 3kf, 3kg, 3kh, 3ki, 3kj, 3kl, 3km, 3kn, 3ko, 3kp, 3kq, 3kr, 3ks, 3kt, 3ku, 3kv, 3kw, 3kx, 3ky, 3kz, 3la, 3lb, 3lc, 3ld, 3le, 3lf, 3lg, 3lh, 3li, 3lj, 3lk, 3ll, 3lm, 3ln, 3lo, 3lp, 3lq, 3lr, 3ls, 3lt, 3lu, 3lv, 3lw, 3lx, 3ly, 3lz, 3ma, 3mb, 3mc, 3md, 3me, 3mf, 3mg, 3mh, 3mi, 3mj, 3mk, 3ml, 3mm, 3mn, 3mo, 3mp, 3mq, 3mr, 3ms, 3mt, 3mu, 3mv, 3mw, 3mx, 3my, 3mz, 3na, 3nb, 3nc, 3nd, 3ne, 3nf, 3ng, 3nh, 3ni, 3nj, 3nk, 3nl, 3nm, 3nn, 3no, 3np, 3nq, 3nr, 3ns, 3nt, 3nu, 3nv, 3nw, 3nx, 3ny, 3nz, 3oa, 3ob, 3oc, 3od, 3oe, 3of, 3og, 3oh, 3oi, 3oj, 3ok, 3ol, 3om, 3on, 3oo, 3op, 3oq, 3or, 3os, 3ot, 3ou, 3ov, 3ow, 3ox, 3oy, 3oz, 3pa, 3pb, 3pc, 3pd, 3pe, 3pf, 3pg, 3ph, 3pi, 3pj, 3pk, 3pl, 3pm, 3pn, 3po, 3pp, 3pq, 3pr, 3ps, 3pt, 3pu, 3pv, 3pw, 3px, 3py, 3pz, 3qa, 3qb, 3qc, 3qd, 3qe, 3qf, 3qg, 3qh, 3qi, 3qj, 3qk, 3ql, 3qm, 3qn, 3qo, 3qp, 3qq, 3qr, 3qs, 3qt, 3qu, 3qv, 3qw, 3qx, 3qy, 3qz, 3ra, 3rb, 3rc, 3rd, 3re, 3rf, 3rg, 3rh, 3ri, 3rj, 3rk, 3rl, 3rm, 3rn, 3ro, 3rp, 3rq, 3rr, 3rs, 3rt, 3ru, 3rv, 3rw, 3rx, 3ry, 3rz, 3sa, 3sb, 3sc, 3sd, 3se, 3sf, 3sg, 3sh, 3si, 3sj, 3sk, 3sl, 3sm, 3sn, 3so, 3sp, 3sq, 3sr, 3ss, 3st, 3su, 3sv, 3sw, 3sx, 3sy, 3sz, 3ta, 3tb, 3tc, 3td, 3te, 3tf, 3tg, 3th, 3ti, 3tj, 3tk, 3tl, 3tm, 3tn, 3to, 3tp, 3tq, 3tr, 3ts, 3tt, 3tu, 3tv, 3tw, 3tx, 3ty, 3tz, 3ua, 3ub, 3uc, 3ud, 3ue, 3uf, 3ug, 3uh, 3ui, 3uj, 3uk, 3ul, 3um, 3un, 3uo, 3up, 3uq, 3ur, 3us, 3ut, 3uu, 3uv, 3uw, 3ux, 3uy, 3uz, 3va, 3vb, 3vc, 3vd, 3ve, 3vf, 3vg, 3vh, 3vi, 3vj, 3vk, 3vl, 3vm, 3vn, 3vo, 3vp, 3vq, 3vr, 3vs, 3vt, 3vu, 3vv, 3vw, 3vx, 3vy, 3vz, 3wa, 3wb, 3wc, 3wd, 3we, 3wf, 3wg, 3wh, 3wi, 3wj, 3wk, 3wl, 3wm, 3wn, 3wo, 3wp, 3wq, 3wr, 3ws, 3wt, 3wu, 3wv, 3ww, 3wx, 3wy, 3wz, 3xa, 3xb, 3xc, 3xd, 3xe, 3xf, 3xg, 3xh, 3xi, 3xj, 3xk, 3xl, 3xm, 3xn, 3xo, 3xp, 3xq, 3xr, 3xs, 3xt, 3xu, 3xv, 3xw, 3xx, 3xy, 3xz, 3ya, 3yb, 3yc, 3yd, 3ye, 3yf, 3yg, 3yh, 3yi, 3yj, 3yk, 3yl, 3ym, 3yn, 3yo, 3yp, 3yq, 3yr, 3ys, 3yt, 3yu, 3yv, 3yw, 3yx, 3yy, 3yz, 3za, 3zb, 3zc, 3zd, 3ze, 3zf, 3zg, 3zh, 3zi, 3zj, 3zk, 3zl, 3zm, 3zn, 3zo, 3zp, 3zq, 3zr, 3zs, 3zt, 3zu, 3zv, 3zw, 3zx, 3zy, 3zz, 3aa, 3ab, 3ac, 3ad, 3ae, 3af, 3ag, 3ah, 3ai, 3aj, 3ak, 3al, 3am, 3an, 3ao, 3ap, 3aq, 3ar, 3as, 3at, 3au, 3av, 3aw, 3ax, 3ay, 3az, 3ba, 3bb, 3bc, 3bd, 3be, 3bf, 3bg, 3bh, 3bi, 3bj, 3bk, 3bl, 3bm, 3bn, 3bo, 3bp, 3bq, 3br, 3bs, 3bt, 3bu, 3bv, 3bw, 3bx, 3by, 3bz, 3ca, 3cb, 3cc, 3cd, 3ce, 3cf, 3cg, 3ch, 3ci, 3cj, 3ck, 3cl, 3cm, 3cn, 3co, 3cp, 3cq, 3cr, 3cs, 3ct, 3cu, 3cv, 3cw, 3cx, 3cy, 3cz, 3da, 3db, 3dc, 3dd, 3de, 3df, 3dg, 3dh, 3di, 3dj, 3dk, 3dl, 3dm, 3dn, 3do, 3dp, 3dq, 3dr, 3ds, 3dt, 3du, 3dv, 3dw, 3dx, 3dy, 3dz, 3ea, 3eb, 3ec, 3ed, 3ee, 3ef, 3eg, 3eh, 3ei, 3ej, 3ek, 3el, 3em, 3en, 3eo, 3ep, 3eq, 3er, 3es, 3et, 3eu, 3ev, 3ew, 3ex, 3ey, 3ez, 3fa, 3fb, 3fc, 3fd, 3fe, 3ff, 3fg, 3fh, 3fi, 3fj, 3fk, 3fl, 3fm, 3fn, 3fo, 3fp, 3fq, 3fr, 3fs, 3ft, 3fu, 3fv, 3fw, 3fx, 3fy, 3fz, 3ga, 3gb, 3gc, 3gd, 3ge, 3gf, 3gg, 3gh, 3gi, 3gj, 3gk, 3gl, 3gm, 3gn, 3go, 3gp, 3gq, 3gr, 3gs, 3gt, 3gu, 3gv, 3gw, 3gx, 3gy, 3gz, 3ha, 3hb, 3hc, 3hd, 3he, 3hf, 3hg, 3hi, 3hj, 3hk, 3hl, 3hm, 3hn, 3ho, 3hp, 3hq, 3hr, 3hs, 3ht, 3hu, 3hv, 3hw, 3hx, 3hy, 3hz, 3ia, 3ib, 3ic, 3id, 3ie, 3if, 3ig, 3ih, 3ii, 3ij, 3ik, 3il, 3im, 3in, 3io, 3ip, 3iq, 3ir, 3is, 3it, 3iu, 3iv, 3iw, 3ix, 3iy, 3iz, 3ja, 3jb, 3jc, 3jd, 3je, 3jf, 3jg, 3jh, 3ji, 3jj, 3jk, 3jl, 3jm, 3jn, 3jo, 3jp, 3jq, 3jr, 3js, 3jt, 3ju, 3jv, 3jw, 3jx, 3jy, 3jz, 3ka, 3kb, 3kc, 3kd, 3ke, 3kf, 3kg, 3kh, 3ki, 3kj, 3kl, 3km, 3kn, 3ko, 3kp, 3kq, 3kr, 3ks, 3kt, 3ku, 3kv, 3kw, 3kx, 3ky, 3kz, 3la, 3lb, 3lc, 3ld, 3le, 3lf, 3lg, 3lh, 3li, 3lj, 3lk, 3ll, 3lm, 3ln, 3lo, 3lp, 3lq, 3lr, 3ls, 3lt, 3lu, 3lv, 3lw, 3lx, 3ly, 3lz, 3ma, 3mb, 3mc, 3md, 3me, 3mf, 3mg, 3mh, 3mi, 3mj, 3mk, 3ml, 3mm, 3mn, 3mo, 3mp, 3mq, 3mr, 3ms, 3mt, 3mu, 3mv, 3mw, 3mx, 3my, 3mz, 3na, 3nb, 3nc, 3nd, 3ne, 3nf, 3ng, 3nh, 3ni, 3nj, 3nk, 3nl, 3nm, 3nn, 3no, 3np, 3nq, 3nr, 3ns, 3nt, 3nu, 3nv, 3nw, 3nx, 3ny, 3nz, 3oa, 3ob, 3oc, 3od, 3oe, 3of, 3og, 3oh, 3oi, 3oj, 3ok, 3ol, 3om, 3on, 3oo, 3op, 3oq, 3or, 3os, 3ot, 3ou, 3ov, 3ow, 3ox, 3oy, 3oz, 3pa, 3pb, 3pc, 3pd, 3pe, 3pf, 3pg, 3ph, 3pi, 3pj, 3pk, 3pl, 3pm, 3pn, 3po, 3pp, 3pq, 3pr, 3ps, 3pt, 3pu, 3pv, 3pw, 3px, 3py, 3pz, 3qa, 3qb, 3qc, 3qd, 3qe, 3qf, 3qg, 3qh, 3qi, 3qj, 3qk, 3ql, 3qm, 3qn, 3qo, 3qp, 3qq, 3qr, 3qs, 3qt, 3qu, 3qv, 3qw, 3qx, 3qy, 3qz, 3ra, 3rb, 3rc, 3rd, 3re, 3rf, 3rg, 3rh, 3ri, 3rj, 3rk, 3rl, 3rm, 3rn, 3ro, 3rp, 3rq, 3rr, 3rs, 3rt, 3ru, 3rv, 3rw, 3rx, 3ry, 3rz, 3sa, 3sb, 3sc, 3sd, 3se, 3sf, 3sg, 3sh, 3si, 3sj, 3sk, 3sl, 3sm, 3sn, 3so, 3sp, 3sq, 3sr, 3ss, 3st, 3su, 3sv, 3sw, 3sx, 3sy, 3sz, 3ta, 3tb, 3tc, 3td, 3te, 3tf, 3tg, 3th, 3ti, 3tj, 3tk, 3tl, 3tm, 3tn, 3to, 3tp, 3tq, 3tr, 3ts, 3tt, 3tu, 3tv, 3tw, 3tx, 3ty, 3tz, 3ua, 3ub, 3uc, 3ud, 3ue, 3uf, 3ug, 3uh, 3ui, 3uj, 3uk, 3ul, 3um, 3un, 3uo, 3up, 3uq, 3ur, 3us, 3ut, 3uu, 3uv, 3uw, 3ux, 3uy, 3uz, 3va, 3vb, 3vc, 3vd, 3ve, 3vf, 3vg, 3vh, 3vi, 3vj, 3vk, 3vl, 3vm, 3vn, 3vo, 3vp, 3vq, 3vr, 3vs, 3vt, 3vu, 3vv, 3vw, 3vx, 3vy, 3vz, 3wa, 3wb, 3wc, 3wd, 3we, 3wf, 3wg, 3wh, 3wi, 3wj, 3wk, 3wl, 3wm, 3wn, 3wo, 3wp, 3wq, 3wr, 3ws, 3wt, 3wu, 3wv, 3ww, 3wx, 3wy, 3wz, 3xa, 3xb, 3xc, 3xd, 3xe, 3xf, 3xg, 3xh, 3xi, 3xj, 3xk, 3xl, 3xm, 3xn, 3xo, 3xp, 3xq, 3xr, 3xs, 3xt, 3xu, 3xv, 3xw, 3xx, 3xy, 3xz, 3ya, 3yb, 3yc, 3yd, 3ye, 3yf, 3yg, 3yh, 3yi, 3yj, 3yk, 3yl, 3ym, 3yn, 3yo, 3yp, 3yq, 3yr, 3ys, 3yt, 3yu, 3yv, 3yw, 3yx, 3yy, 3yz, 3za, 3zb, 3zc, 3zd, 3ze, 3zf, 3zg, 3zh, 3zi, 3zj, 3zk, 3zl, 3zm, 3zn, 3zo, 3zp, 3zq, 3zr, 3zs, 3zt, 3zu, 3zv, 3zw, 3zx, 3zy, 3zz, 3aa, 3ab, 3ac, 3ad, 3ae, 3af, 3ag, 3ah, 3ai, 3aj, 3ak, 3al, 3am, 3an, 3ao, 3ap, 3aq, 3ar, 3as, 3at, 3au, 3av, 3aw, 3ax, 3ay, 3az, 3ba, 3bb, 3bc, 3bd, 3be, 3bf, 3bg, 3bh, 3bi, 3bj, 3bk, 3bl, 3bm, 3bn, 3bo, 3bp, 3bq, 3br, 3bs, 3bt, 3bu, 3bv, 3bw, 3bx, 3by, 3bz, 3ca, 3cb, 3cc, 3cd, 3ce, 3cf, 3cg, 3ch, 3ci, 3cj, 3ck, 3cl, 3cm, 3cn, 3co, 3cp, 3cq, 3cr, 3cs, 3ct, 3cu, 3cv, 3cw, 3cx, 3cy, 3cz, 3da, 3db, 3dc, 3dd, 3de, 3df, 3dg, 3dh, 3di, 3dj, 3dk, 3dl, 3dm, 3dn, 3do, 3dp, 3dq, 3dr, 3ds, 3dt, 3du, 3dv, 3dw, 3dx, 3dy, 3dz, 3ea, 3eb, 3ec, 3ed, 3ee, 3ef, 3eg, 3eh, 3ei, 3ej, 3ek, 3el, 3em, 3en, 3eo, 3ep, 3eq, 3er, 3es, 3et, 3eu, 3ev, 3ew, 3ex, 3ey, 3ez, 3fa, 3fb, 3fc, 3fd, 3fe, 3ff, 3fg, 3fh, 3fi, 3fj, 3fk, 3fl, 3fm, 3fn, 3fo, 3fp, 3fq, 3fr, 3fs, 3ft, 3fu, 3fv,				

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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 Rulings)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
PRC-007-1.R1	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(i) (see Assessment Report 9)	1 - New standard. Incorporates reliability objectives of PRC-001-1.1(i) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1.R2 mandates an entity periodically perform Protection System Coordination Studies and/or compare existing Fault current values to established Fault current baselines for Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current. PRC-001-1(i) to PRC-027-1 Mapping Document	TO, GO, DP	Docket No. RM16-22-000; Order No. 847, issued June 7, 2018	13-Aug-2019	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	New process required and a new system study.	100,000	20,000	18 months after BCUC approval
PRC-027-1.R2	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(ii) (see Assessment Report 9)	1 - New standard. Incorporates reliability objectives of PRC-001-1.1(i) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1.R2 mandates an entity to establish a process for developing and maintaining Protection System settings for BES Elements to operate in the intended sequence during Faults. PRC-001-1(ii) to PRC-027-1 Mapping Document	TO, GO, DP	Docket No. RM16-22-000; Order No. 847, issued June 7, 2018	13-Aug-2019	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	New process required and a new short circuit study.	100,000	20,000	18 months after BCUC approval
PRC-027-1.R3	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(iii) (see Assessment Report 9)	1 - New standard. Incorporates reliability objectives of PRC-001-1.1(i) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1.R3 mandates that an entity utilize the process established in accordance with PRC-027-1.R1. PRC-001-1(iii) to PRC-027-1 Mapping Document	TO, GO, DP	Docket No. RM16-22-000; Order No. 847, issued June 7, 2018	13-Aug-2019	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	New relay settings required.	50,000	10,000	2 years after BCUC approval
VAR-001-5.R1	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.R2	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.R3	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.R6	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.E.A.13	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - No changes to requirement; measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and otherwise, minor format changes. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.E.A.14	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - In E.A.14 "Area" was changed to "area"; measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and otherwise minor format changes. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.E.A.15	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - This requirement is the same as VAR-001-4.2 E.A.16 (no change to requirement); previous VAR-001-4.2 E.A.15 and associated elements were deleted because the task is contained in VAR-002-4.1, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3 as a lesser included task. Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	GOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.E.A.16	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - This requirement is the same as VAR-001-4.2 E.A.17 (no change to requirement). Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	TOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			
VAR-001-5.E.A.17	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flow, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5 - This requirement is the same as VAR-001-4.2 E.A.18 (no change to requirement). Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	GOP	Docket No. RD18-8-000, issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	Not Applicable			

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
VAR-002-WECC-2 (retire standard)	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	N/A Retired standard (see Assessment Report 9)	N/A Retired standard	GO, TOP.	Docket No. RD18-1-0000 Issued September 6, 2018	5-Sep-2018	No Implementation time required: Retired standard US Inactive Date: Sep-5-2018	Not Applicable			

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CPPR, CPCD, CPPAD (DP, DPUFLS Only)

FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 6, 2017 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 06, 2017 Glossary of Terms	Current BCUC Adopted Definition from October 06, 2017 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 Organizational Activities and Reliability/Suitability Impact (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 (\$)	
Operational Planning Analysis *Glossary term is specific to the new PER-006-1 standard in addition to the currently adopted IRO-008-1 standard.	OPA	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.)	Operational Planning Analysis (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020	No impact			
Protection System Coordination Study *Glossary term is specific to the new PRC-027-1 standard.		An analysis to determine whether Protection Systems operate in the intended sequence during Faults.	New	N/A	7-Jun-2018	1-Oct-2020	New procedure required for PRC-027-1. New system studies and relay settings required.	Included with PRC-027-1	Included with PRC-027-1	Two years after BCUC adoption
Real-time Assessment *Glossary term is specific to the new PER-006-1 standard in addition to the currently adopted IRO-008-1 standard.	RTA	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.)	Real-time Assessment (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020	No impact			
Removable Media *Glossary term is specific to the revised CIP-003-7 standard in addition to the currently adopted CIP-010-2 standard.		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.	Removable Media (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020	New policies required, may involve new hardware and software.	See comments on CIP-003-7	See comments on CIP-003-7	One year after Commission approval
Transient Cyber Asset *Glossary term is specific to the revised CIP-003-7 standard in addition to the currently adopted CIP-010-2 standard.	TCA	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.	Transient Cyber Asset (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020	New policies required, may involve new hardware and software.	See comments on CIP-003-7	See comments on CIP-003-7	One year after Commission approval

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FortisBC Inc. (TO, TOP, GO, GOP, RP, TP, DP, TSP)

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the Mapping document)	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 (\$)		BCUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									One Time (\$)	Ongoing (\$)	
CIP-003-7 R1	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - Minor modification of requirement language to incorporate a policy for low impact BES systems into CIP-003-7 R1.2 (moved from CIP-003-5 R2) and addition of low impact policy requirements for Transient Cyber Assets and Removable Media as well as CIP Exceptional Circumstances. CIP-003-7 R1.1 and subparts have been moved from CIP-003-5 R1.1 to R1.9 and remain specific to high impact and medium impact policies. No mapping document available.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6 Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	Device and configuration changes are required at LOW BES systems as well as identification of BCAs and creation of associated documentation.	250,000 - 475,000	30,000 - 60,000	Recommended effective date 24-36 months after BCUC approval.
CIP-003-7 R2	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - minor modifications to remove ambiguous language. CIP-003-5 to CIP-003-7 Mapping Document	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6 Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	See CIP-003-7 R1	See CIP-003-7 R1	See CIP-003-7 R1	See CIP-003-7 R1
CIP-003-7 R3	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - No change to this requirement from previous version. CIP-003-5 to CIP-003-7 Mapping Document	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6 Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	See CIP-003-7 R1	See CIP-003-7 R1	See CIP-003-7 R1	See CIP-003-7 R1
CIP-003-7 R4	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - No change to this requirement from previous version. CIP-003-5 to CIP-003-7 Mapping Document	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approval. The implementation plan does not alter the previously-approved initial compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6 Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003-7. US Enforcement Date: 01-Jan-2020	See CIP-003-7 R1	See CIP-003-7 R1	See CIP-003-7 R1	See CIP-003-7 R1

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FortisBC Inc. (TO, TOP, GO, GOP, RP, TP, DP, TSP)

FERC Approved New/Revised/Deleted Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback opportunities)	FERC Approved Revision (Hyperlinks to the response document)	Functional Applicability of FERC Approved Standard/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 Rulings)	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/Subsidiary Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (B) (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 (B)	Cost Ongoing (B)	
BAL-003.3 R1	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-003-2 (see Assessment Report 10)	2 - New requirement added to R1 to (i) notify the RC if entity is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to limit/follow its Most Severe Single Contingency which prevents compliance with recovery of Reporting ACES, and (ii) provide the RC with an ACE recovery plan, including target recovery time.	BA, RSG	Docket No. RD18-7-000, Issued September 25, 2018	25-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Jun-2019	FortisBC is not registered for these functions.	No additional costs.	No additional costs.	N/A
			Mapping document: not available								
BAL-003.3 R2	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-003-2 (see Assessment Report 10)	2 - No changes to this requirement from previous version.	BA, RSG	Docket No. RD18-7-000, Issued September 25, 2018	25-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Jun-2019	FortisBC is not registered for these functions.	No additional costs.	No additional costs.	N/A
			Mapping document: not available								
BAL-003.3 R3	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-003-2 (see Assessment Report 10)	2 - No changes to this requirement from previous version.	BA, RSG	Docket No. RD18-7-000, Issued September 25, 2018	25-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Jun-2019	FortisBC is not registered for these functions.	No additional costs.	No additional costs.	N/A
			Mapping document: not available								
BAL-004.2 (active standard)	Name: Time Error Correction Description: The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the interconnection.	N/A - Retired standard (see Assessment Report 1)	N/A - Retired standard	RC, BA	Docket No. RD17-1-000, Issued January 18, 2017	18-Jan-2017	No implementation time required: Retired standard US Inactive Date: 1-April-2017	FortisBC is not registered for these functions.	No additional costs.	No additional costs.	N/A
BAL-004-WEECC-3 R1	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - New criteria for month-end absolute value of on and off peak Accumulated Primary Inadvertent Interchange.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R2	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R3	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R4	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R5	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R6	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R7	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
BAL-004-WEECC-3 R8	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) payback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WEECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
			Mapping document not available								
EOP-004.4 R1	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004-3 (see Assessment Report 10)	4 - Revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting; requirement R3 has been retired. EOP-004-3 to EOP-004.4 Mapping document	RC, BA, TO, TOP, GO, GOP, DP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	28-Jan-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Minimal changes to FortisBC processes. (This analysis is contingent that new event reporting processes to be implemented by the BC Hydro RC will not be significantly different than the current Peak RC processes.)	No additional costs.	No additional costs.	Recommended effective date immediately after BCUC approval. (This analysis is contingent that new event reporting processes to be implemented by the BC Hydro RC will not be significantly different than the current Peak RC processes.)
EOP-004.4 R2	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004-3 (see Assessment Report 10)	4 - Minor revisions made to requirement R2 for clarity including a reference to Attachment 1, revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting; requirement R3 has been retired.	RC, BA, TO, TOP, GO, GOP, DP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	28-Jan-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-004-4 R1	See EOP-004-4 R1	See EOP-004-4 R1	See EOP-004-4 R2

FERC Approved New/Revised/Refined Standard/Requirement (Hyperlinks to the Standard and RSAMs)	Standard Name and Description	Current BCLC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	Functional Applicability of FERC Approved Standard/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 Rulings)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (B) (Press Alt-Enter to insert a carriage return in a cell)		BCLC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time (B)	Cost Ongoing (B)	
			EOP-005-3 to EOP-005-4 Mapping document								
EOP-005-3 R1	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- Minor wording changes only. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Minimal changes to FortisBC processes. (This analysis is contingent that new system restoration processes, reviews, and training skills to be implemented by the BC Hydro RC will not be significantly different than the current Peak RC processes.)	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval. (This analysis is contingent that new system restoration processes, reviews, and training skills to be implemented by the BC Hydro RC will not be significantly different than the current Peak RC processes.)
EOP-005-3 R2	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- Changes to the specific roles and tasks within an approved restoration plan must now be communicated prior to the "effective date" of the plan instead of the "implementation date". EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R3	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- No changes to this requirement from previous version. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R4	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- The conditions for submission of related restoration plan to the RC has been updated. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R5	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- Copy of the latest RC approved restoration plan must now be available in primary/backup control rooms prior to the "effective date" of the plan instead of the "implementation date". EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R6	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- No material changes to this requirement from the previous version. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R7	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R6; EOP-005-2 R7 has been retired. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R8	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R10 with the exception of an additional training requirement as transition of demand and resource balance within a TOP area to the BCLC; EOP-005-2 R8 has been retired. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R9	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R11; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	TOP, TO, GP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R10	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R12; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	TOP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R11	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R13; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	TOP, GQP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R12	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R14; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GQP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R13	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R15; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GQP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R14	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R16; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GQP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R15	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R17; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GQP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1
EOP-005-3 R16	Name: System Restoration from Backstart Resources Description: Ensure plans, facilities, and personnel are prepared to enable System restoration from Backstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R18; no material changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GQP	Docket No. RM17-12-000, Order No. 840, issued January 18, 2018	26-March-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1	See EOP-005-3 R1

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAMs)	Standard Name and Description	Current BCLC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping documents)	Functional Applicability of FERC Approved Standard/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 Rulings)	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/Safety Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (B) (Press Alt-Enter to insert a carriage return in a cell)		BCLC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time (B)	Cost Ongoing (B)	
EOP-006-3 R1	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. Retirement of EOP-006-2 Parts R1.2, R1.3, R1.4. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R2	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. No changes to this requirement from previous version. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R3	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. No changes to this requirement from previous version. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R4	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. Now requires RC to provide written notification of any conflicts discovered during the review of neighbouring RC's restoration plan within 60 calendar days of receipt. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R5	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. Clarifies that the RC is to provide notification to the TOP of approval or disapproval of restoration plans. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R6	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. Copy of the latest RC's restoration plan must now be available in primary/backup control rooms prior to the "effective date" of the plan instead of the "implementation date". EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R7	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. This requirement is the same as EOP-006-2 R9; No material changes to the requirement. EOP-006-2 R7 has been retired. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-3 R8	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.	EOP-006-2 (see Assessment Report 7)	3. This requirement is the same as EOP-006-2 R10; no material changes to the requirement. EOP-006-2 R8 has been retired. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-2 R1	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. R1 eliminated timing requirement to restore the primary control centre functionality in the current Operating Plan, adopted phrase "data exchange capabilities" for previously used phrase "data communication" which is consistent with IEC/TOP standards, adopted previously defined term (COM-001-20, "Interpersonal Communication" for previously used term Voice communications). EOP-008-1 to EOP-008-2 Mapping document	RC, TOP, BA	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	Minimal changes to FortisBC documentation.	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval.
EOP-006-2 R2	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, TOP, BA	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1
EOP-006-2 R3	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. R3 revised "depend on" to "applicable to" - to clarify the intent of having the back-up control center to meet compliance with Reliability Standards. EOP-008-1 to EOP-008-2 Mapping document	RC	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	FortisBC is not registered for this function.	No additional costs.	No additional costs.	N/A
EOP-006-2 R4	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. R4 revised "depend on" to "applicable to" - to clarify the intent of having the back-up control center to meet compliance with Reliability Standards. EOP-008-1 to EOP-008-2 Mapping document	BA, TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1
EOP-006-2 R5	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1
EOP-006-2 R6	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1
EOP-006-2 R7	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	3. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA and TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1
EOP-006-2 R8	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2. No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 849, Issued January 18, 2018	26-Mar-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval, US Enforcement Date: 01-Apr-2019.	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1	See EOP-008-2 R1

FERC Approved New/Revised/Refined Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCLC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping documents)	Functional Applicability of FERC Approved Standard/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 Rulings)	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/Safety Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (B) (Press Alt-Enter to insert a carriage return in a cell)		BCLC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time (B)	Cost Ongoing (B)	
FAC-S01-WEECC-2 R1	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP) and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-S01-WEECC-1 (see Assessment Report 5)	2. FAC-S01-WEECC-1 Attachment 1 "Transmission Line and Station Maintenance" details have been moved to FAC-S01-WEECC-2 Attachment A and minor modest changes to the mandatory minimum requirements for "Transmission Maintenance and Inspection Plan" (TMIP) includes two new sections "Maintenance Methodology" and "Periodicity", new attachment B - Major WECC Transfer Paths in the BES is also included in the revised standard. Requirement R1 has been modified in alignment with the above change, and requires TO to have a TMIP according to Attachment A. Mapping document not available in WECC/NERC sites.	TO	Docket No. RD18-6-000, Issued May 30, 2018	20 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval US Enforcement Date: 01-Jul-2018	Minimal changes to FortiBCLC processes.	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval.
FAC-S01-WEECC-2 R2	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP) and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-S01-WEECC-1 (see Assessment Report 5)	3. FAC-S01-WEECC-1 R1.1 was moved to FAC-S01-WEECC-2 R2 with modifications to add clarity - i.e. annual TMIP update "as required" is now changed to "reflect all changes to it's TMIP". FAC-S01-WEECC-1 R2 has been revised. Mapping document not available in WECC/NERC sites.	TO	Docket No. RD18-6-000, Issued May 30, 2018	20 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval US Enforcement Date: 01-Jul-2018	See FAC-S01-WEECC-2 R1	See FAC-S01-WEECC-2 R1	See FAC-S01-WEECC-2 R1	See FAC-S01-WEECC-2 R1
FAC-S01-WEECC-4 R1	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP) and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-S01-WEECC-1 (see Assessment Report 5)	2. No major change to this requirement, language modification - i.e. "Implement and follow" has been replaced with "adhere" Mapping document not available in WECC/NERC sites.	TO	Docket No. RD18-6-000, Issued May 30, 2018	20 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval US Enforcement Date: 01-Jul-2018	See FAC-S01-WEECC-2 R1	See FAC-S01-WEECC-2 R1	See FAC-S01-WEECC-2 R1	See FAC-S01-WEECC-2 R1
PER-003-2 R1	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 (see Assessment Report 6) and PER-004-2 (see Assessment Report 5)	2. No material change to this requirement apart from a footnote reference to clarify that the reference to NERC Reliability Operator' certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification Program Manual. Mapping document not available.	RC	Docket No. RD18-6-000, Issued November 21, 2018	21 Nov 18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval US Enforcement Date: 01-Jul-2019	FortiBCLC is not registered for this function.	No additional costs.	No additional costs.	N/A
PER-003-2 R2	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 (see Assessment Report 6) and PER-004-2 (see Assessment Report 5)	2. No material change to this requirement apart from a footnote reference to clarify that the reference to NERC Reliability Operator' certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification Program Manual. Mapping document not available.	TO	Docket No. RD18-6-000, Issued November 21, 2018	21 Nov 18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval US Enforcement Date: 01-Jul-2019	Minimal changes to FortiBCLC documentation.	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval.
PER-003-2 R3	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 (see Assessment Report 6) and PER-004-2 (see Assessment Report 5)	2. No material change to this requirement apart from a footnote reference to clarify that the reference to NERC Reliability Operator' certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification Program Manual. Mapping document not available.	BA	Docket No. RD18-6-000, Issued November 21, 2018	21 Nov 18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval US Enforcement Date: 01-Jul-2019	FortiBCLC is not registered for this function.	No additional costs.	No additional costs.	N/A
PER-006-1 R1	Name: Specific Training for Personnel Description: To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.	PRC-001-1.1(i) (see Assessment Report 9)	1. New standard - PER-006-1 R1 replaces PRC-001-1.1(i) R1, also the referenced term Special Protection System (SPS) has been replaced with Remedial Action Scheme (RAS). PRC-001-1(i) to PER-006-1 Mapping Document	GOP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval US Enforcement Date: 01-Oct-2020	Minimal changes to FortiBCLC documentation.	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval.
PRC-025-1 R1	Name: Generator Relay Loadability Description: To set load-responsive protective relays associated with generation Function: R1 level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	PRC-025-1 (see Assessment Report 8)	2. Provide clarification for specific facility applications and load-responsive protective relays, LV protection devices that do not have adjustable settings is included in the Relay settings exclusion; provided alternative loadability Options for Table 1 specific to dispersed power producing resources; eliminated the term "pickup" in Table 1 to better align with the intent of the standard for relays to "not trip", and provided clarity on few miscellaneous items. Mapping Document not available	GO, TO, DP	Docket No. RD18-6-000, Issued May 2, 2018	2-May-2018	Implementation Time: First day of the first calendar quarter after the effective date of the applicable governmental authority's approval of the standard US Enforcement Date: 01-Jul-2018 Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval US Enforcement Date: 01-Oct-2020	Minimal changes to FortiBCLC documentation.	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval.
PRC-027-1 R1	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(i) (see Assessment Report 9)	1. New standard - Incorporates reliability objectives of PRC-001-1.1(i) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1 R2 mandates an entity periodically perform Protection System Coordination Studies and/or compare existing Fault current values to established Fault current baselines for Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current. PRC-001-1(i) to PRC-027-1 Mapping Document	TO, GO, DP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval US Enforcement Date: 01-Oct-2020	FortiBCLC will need to establish a new process for developing new and revised Protection System settings and perform a Protection System Coordination Study for each BES element in the FortiBCLC system.	75,000 - 100,000	No additional costs.	Recommended effective date 24 months after BCLC approval.
PRC-027-1 R2	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(i) (see Assessment Report 9)	1. New standard - Incorporates reliability objectives of PRC-001-1.1(i) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1 R2 mandates an entity to establish a process for developing and maintaining Protection System settings for BES Elements to operate in the intended sequence during Faults. PRC-001-1(i) to PRC-027-1 Mapping Document	TO, GO, DP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval US Enforcement Date: 01-Oct-2020	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1
PRC-027-1 R3	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(i) (see Assessment Report 9)	1. New standard - Incorporates reliability objectives of PRC-001-1.1(i) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1 R3 mandates that an entity utilize the process established in accordance with PRC-027-1 R1. PRC-001-1(i) to PRC-027-1 Mapping Document	TO, GO, DP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval US Enforcement Date: 01-Oct-2020	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1	See PRC-027-1 R1
VAR-001-5 R1	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD18-8-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority US Enforcement Date: 01-Jan-2019	Minimal changes to FortiBCLC documentation.	No additional costs.	No additional costs.	Recommended effective date immediately after BCLC approval.
VAR-001-5 R2	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD18-8-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority US Enforcement Date: 01-Jan-2019	See VAR-001-5 R1	See VAR-001-5 R1	See VAR-001-5 R1	See VAR-001-5 R1

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping documents)	Functional Applicability of FERC Approved Standard/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 Rulings)	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/Subsidiary Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
VAR-001-5.E.A.01	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-5.E.A.02	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- No changes to requirement; minor format changes to standard. No mapping document available.	TOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-5.E.A.13	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- No changes to requirement; measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and otherwise, minor format changes. No mapping document available.	TOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-5.E.A.14	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- In E.A.14 "Area" was changed to "area"; measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and otherwise, minor format changes. No mapping document available.	TOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-5.E.A.15	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- This requirement is the same as VAR-001-4.2 E.A.16 (no change to requirement); previous VAR-001-4.2 E.A.15 and associated elements were deleted because the task is contained in VAR-001-4.2, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3 as a lesser included task. Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	GOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-5.E.A.16	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- This requirement is the same as VAR-001-4.2 E.A.17 (no change to requirement). Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	TOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-5.E.A.17	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- This requirement is the same as VAR-001-4.2 E.A.18 (no change to requirement). Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	GOP	Docket No. RD19-8-000; issued October 15, 2019	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	See VAR-001-5.R1	See VAR-001-5.R1	See VAR-001-5.R1	
VAR-001-WECG-3 (retire standard)	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	N/A Retired standard (see Assessment Report 9)	N/A Retired standard	GO, TOP	Docket No. RD18-1-000; issued September 5, 2018	5-Sep-2018	No implementation time required. Retired standard US Inactive Date: Sep-5-2018	Minimal changes to FortisBC documentation.	No additional costs.	No additional costs.	Recommended retirement date immediately after BCUC approval.

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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. (TO, TOP, GO, GOP, RP, TP, DP, TSP)

FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 6, 2017 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 06, 2017 Glossary of Terms	Current BCUC Adopted Definition from October 06, 2017 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 Organizational Activities and Reliability/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental Cost Associated with Revised/Retired 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 (\$)	
Operational Planning Analysis *Glossary term is specific to the new PER-006-1 standard in addition to the currently adopted RO-008-1 standard.	OPA	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.)	Operational Planning Analysis (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020	No impact to FortisBC.	No additional costs.	No additional costs.	Recommended effective date immediately after BCUC approval.
Protection System Coordination Study *Glossary term is specific to the new PRC-027-1 standard.		An analysis to determine whether Protection Systems operate in the intended sequence during Faults.	New	N/A	7-Jun-2018	1-Oct-2020	Please see comments provided for PRC-027-1 in the Standards feedback survey form.	See PRC-027-1	See PRC-027-1	Coincide with effective date of PRC-027-1 standard after BCUC adoption.
Real-time Assessment *Glossary term is specific to the new PER-006-1 standard in addition to the currently adopted RO-008-1 standard.	RTA	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.)	Real-time Assessment (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020	No impact to FortisBC.	No additional costs.	No additional costs.	Recommended effective date immediately after BCUC approval.
Removable Media *Glossary term is specific to the revised CIP-003-7 standard in addition to the currently adopted CIP-010-2 standard.		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.	Removable Media (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020	No impact to FortisBC.	No additional costs.	No additional costs.	Recommended effective date immediately after BCUC approval.
Transient Cyber Asset *Glossary term is specific to the revised CIP-003-7 standard in addition to the currently adopted CIP-010-2 standard.	TCA	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.	Transient Cyber Asset (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020	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 twelfth 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.

NORTHWOOD PULP MILL - CANFOR PULP LIMITED PARTNERSHIP, (DP)

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the Mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	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)
									One Time (\$)	Ongoing (\$)	
CIP-003.7 R1	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - Minor modification of requirement language to incorporate a policy for low impact BES systems into CIP-003-7 R1.2 (moved from CIP-003-5 R2) and addition of low impact policy requirements for Transient Cyber Assets and Removable Media as well as CIP Exceptional Circumstances. CIP-003-7 R1.1 and subparts have been moved from CIP-003-5 R1.1 to R1.5 and remain specific to high impact and medium impact policies.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously approved initial compliance dates for Reliability Standard CIP-003.6 other than the compliance date for Reliability Standard CIP-003.6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	No impact for DP	No cost	No cost	N/A
			No mapping document available.								
CIP-003.7 R2	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - minor modifications to remove ambiguous language.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously approved initial compliance dates for Reliability Standard CIP-003.6 other than the compliance date for Reliability Standard CIP-003.6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	No impact for DP	No cost	No cost	N/A
			CIP-003.6 to CIP-003.7 Mapping Document								
CIP-003.7 R3	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - No change to this requirement from previous version.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously approved initial compliance dates for Reliability Standard CIP-003.6 other than the compliance date for Reliability Standard CIP-003.6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	No impact for DP	No cost	No cost	N/A
			CIP-003.6 to CIP-003.7 Mapping Document								
CIP-003.7 R4	Name: Cyber Security — Security Management Controls Description: To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the Bulk Electric System (BES).	CIP-003-5 (see Assessment Report 8)	7 - No change to this requirement from previous version.	BA, GOP, GO, IC OR IA, RC, TOP, TO, DP	Docket No. RM17-11-000, Order No. 843, Issued April 19, 2018.	25-Jun-2018	Implementation Time: First day of the first calendar quarter that is eighteen months after applicable regulatory approvals. The implementation plan does not alter the previously approved initial compliance dates for Reliability Standard CIP-003.6 other than the compliance date for Reliability Standard CIP-003.6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for Reliability Standard CIP-003.7. US Enforcement Date: 01-Jan-2020	No impact for DP	No cost	No cost	N/A
			CIP-003.6 to CIP-003.7 Mapping Document								

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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 (e.g. TO, DP, GO, DP, etc.):

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and PSAs/RSs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheet)	FERC Approved Revision (Hyperlinks to the mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, 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 (\$)	
BAL-002-3.R1	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002-2 (see Assessment Report 10)	2 - New requirement added to R1 to (i) notify the RC if entity is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, or has depleted its Contingency Reserve to a level below its Most Severe Single-Contingency which prevents compliance with recovery of Reporting ACE, and (ii) provide the RC with an ACE recovery plan, including target recovery time.	BA, RSG	Docket No. RD18-2-000, Issued September 25, 2018	25-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-002-3.R2	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002-2 (see Assessment Report 10)	2 - No changes to this requirement from previous version.	BA, RSG	Docket No. RD18-2-000, Issued September 25, 2018	25-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-002-3.R3	Name: Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event Description: To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.	BAL-002-2 (see Assessment Report 10)	2 - No changes to this requirement from previous version.	BA, RSG	Docket No. RD18-2-000, Issued September 25, 2018	25-Sep-2018	Implementation Time: First day of the first calendar quarter that is six months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-0 (retired standard)	Name: Time Error Correction Description: The purpose of the standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the interconnection	N/A - Retired standard (see Assessment Report 1)	N/A - Retired standard	RC, BA	Docket No. RD17-1-000, Issued January 19, 2017	19-Jan-2017	No Implementation time required: Retired standard US Inactive Date: 1-April-2017	No impact on DP	No cost	No cost	N/A
BAL-004-WECC-3.B1	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - New criteria for month-end absolute value of on and off peak Accumulated Primary Inadvertent Interchange.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B2	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B3	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B4	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B5	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B6	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B7	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
BAL-004-WECC-3.B8	Name: Automatic Time Error Correction Description: To maintain interconnection frequency and to ensure that Time Error Corrections and Primary Inadvertent Interchange (PII) playback are effectively conducted in a manner that does not adversely affect the reliability of the interconnection.	BAL-004-WECC-2 (see Assessment Report 7)	2 - No changes to the requirement from previous version.	BA	Docket No. RD18-2-000, Issued May 30, 2018	30-May-2018	Implementation Time: First day of the second quarter following applicable regulatory approval. US Enforcement Date: 01-Oct-2018	No impact on DP	No cost	No cost	N/A
			Mapping document not available								
EOP-004-4.B1	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004-3 (see Assessment Report 10)	4 - Revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting; requirement R3 has been retired.	RC, BA, TO, TOP, GO, GOP, DP	Docket No. RM17-12-000, Order No. RM, Issued January 19, 2018	29-Jan-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Already in place. We already inform BC Hydro in case of events, as per our Local Operating Order.	No cost	No cost	Compliant from the time of adoption by BCUC
			EOP-004-3 to EOP-004-4 Mapping document								
EOP-004-4.B2	Name: Event Reporting Description: To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.	EOP-004-3 (see Assessment Report 10)	4 - Minor revisions made to requirement R2 for clarity including a reference to Attachment 1, revisions made to Attachment 1 clarifying roles and responsibilities for event reporting, event types, and thresholds for reporting; requirement R3 has been retired.	RC, BA, TO, TOP, GO, GOP, DP	Docket No. RM17-12-000, Order No. RM, Issued January 19, 2018	29-Jan-2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	Already in place. We already inform BC Hydro in case of events, as per our Local Operating Order.	No cost	No cost	Compliant from the time of adoption by BCUC
			EOP-004-3 to EOP-004-4 Mapping document								

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (B) (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 (B)	Cost Ongoing (B)	
EOP-005-2 R1	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- Minor wording changes only.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R2	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- Changes to the specific roles and tasks within an approved restoration plan must now be communicated prior to the "effective date" of the plan instead of the "implementation date".	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R3	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- No changes to this requirement from previous version.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R4	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- The conditions for submission of revised restoration plan to the RC has been updated.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R5	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- Copy of the latest RC approved restoration plan must now be available in primary/backup control rooms prior to the "effective date" of the plan instead of the "implementation date".	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R6	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- No material changes to this requirement from the previous version.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R7	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R6; EOP-005-2 R7 has been retired.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R8	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R8D with the exception of an additional training requirement on transition of Demand and resource balance within a TOP's area to the BA; EOP-005-2 R8 has been retired.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R9	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R11; no changes to the requirement.	TOP, TO, DP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R10	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R12; no changes to the requirement.	TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R11	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R13; no changes to the requirement.	TOP, GOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R12	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R14; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R13	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R15; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								
EOP-005-2 R14	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R16; no changes to the requirement.	GOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26-Mar-2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval. US Enforcement Date: 01-Apr-2019	No impact on DP	No cost	No cost	NA
			EOP-005-2 to EOP-005-3 Mapping document								

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAWs)	Standard Name and Description	Current BCLUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	Functional Applicability of FERC Approved Standard/Requirement	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (\$) (Press Alt-Enter to insert a carriage return in a cell)		BCLUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time (\$)	Cost Ongoing (\$)	
EOP-005-2 R15	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R17; no changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GOP	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-005-2 R16	Name: System Restoration from Blackstart Resources Description: Ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-005-2 (see Assessment Report 7)	3- This requirement is the same as EOP-005-2 R16; no material changes to the requirement. EOP-005-2 to EOP-005-3 Mapping document	GOP	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R1	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- Retirement of EOP-006-2 Parts R1.2, R1.3, R1.4. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R2	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- No changes to this requirement from previous version. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R3	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- No changes to this requirement from previous version. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R4	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- Now requires RC to provide written notification of any conflicts discovered during the reviews of neighbouring RC's restoration plan within 60-calendar days of receipt. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R5	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- Clarifies that the RC is to provide notification to the TOP of approval or disapproval of restoration plans. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R6	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- Copy of the latest RC's restoration plan must now be available in primary/backup control rooms prior to the "effective date" of the plan instead of the "implementation date". EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R7	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- This requirement is the same as EOP-006-2 R5; No material changes to the requirement. EOP-006-2 R7 has been retired. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-006-3 R8	Name: System Restoration Coordination Description: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the interconnection.	EOP-006-2 (see Assessment Report 7)	3- This requirement is the same as EOP-006-2 R30; no material changes to the requirement. EOP-006-2 R8 has been retired. EOP-006-2 to EOP-006-3 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-008-2 R1	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2- R1 eliminated timing requirement to restore the primary control centre functionality in the current Operating Plan, adopted phrase "data exchange capabilities" for previously used phrase "data communications" which is consistent with R0/TOP standards, adopted previously defined term (CDM 001-2), "Interpersonal Communications" for previously used term Voice communications; EOP-008-1 to EOP-008-2 Mapping document	RC, TOP, BA	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-008-2 R2	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2- No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping document	RC, TOP, BA	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-008-2 R3	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2- R3 revised "depend on" to "applicable to"- to clarify the intent of having the back-up control center to meet compliance with Reliability Standards. EOP-008-1 to EOP-008-2 Mapping document	RC	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA
EOP-008-2 R4	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2- R4 revised "depend on" to "applicable to"- to clarify the intent of having the back-up control center to meet compliance with Reliability Standards.	BA, TOP	Docket No. RM17-12-000; Order No. 840; Issued: January 18, 2018	26 Mar 2019	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval; US Enforcement Date: 01-Apr-2019.	No impact on DP	No cost	No cost	NA

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCLUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (B) (Press Alt-Enter to insert a carriage return in a cell)		BCLUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time (B)	Cost Ongoing (B)	
	Deleted: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	(see Assessment Report 7)	EOP-008-1 to EOP-008-2 Mapping Document				see Assessment Report - Implementation				
EOP-008-2 RS	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2 - No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping Document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26 May 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval US Enforcement Date: 01 Apr 2018	No impact on DP	No cost	No cost	NA
EOP-008-2 RS	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2 - No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping Document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26 May 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval US Enforcement Date: 01 Apr 2018	No impact on DP	No cost	No cost	NA
EOP-008-2 RT	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2 - No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping Document	RC, BA and TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26 May 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval US Enforcement Date: 01 Apr 2018	No impact on DP	No cost	No cost	NA
EOP-008-2 RS	Name: Loss of Control Center Functionality Description: Ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable.	EOP-008-1 (see Assessment Report 7)	2 - No changes to this requirement from previous version. EOP-008-1 to EOP-008-2 Mapping Document	RC, BA, TOP	Docket No. RM17-12-000, Order No. 840, Issued January 18, 2018	26 May 2018	Implementation Time: First day of the first calendar quarter that is twelve months following applicable regulatory approval US Enforcement Date: 01 Apr 2018	No impact on DP	No cost	No cost	NA
FAC-501-WECC-2 R1	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP), and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-501-WECC-1 (see Assessment Report 5)	2 - FAC-501-WECC-1 Attachment 1 "Transmission Line and Stations Maintenance" details have been moved to FAC-501-WECC-2 Attachment A and makes modest changes to the mandatory minimum requirements for "Transmission Maintenance and Inspection Plan" (TMIP) includes two new sections: "Maintenance Methodology" and "Periodicity"; new attachment B - Major WECC Transfer Paths in the BES is also included in the revised standard. Requirement R1 has been modified in alignment with the above change, and requires TO to have a TMIP according to Attachment A. Mapping document not available in WECC/NERC sites.	TO	Docket No. RD18-5-000, Issued May 30, 2018	30 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval US Enforcement Date: 01 Jul 2018	No impact on DP	No cost	No cost	NA
FAC-501-WECC-2 R2	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP), and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-501-WECC-1 (see Assessment Report 5)	2 - FAC-501-WECC-1 R1.3 was moved to FAC-501-WECC-2 R2 with modifications to add clarity - i.e. annual TMIP update "as required" is now changed to "reflect all changes to its TMIP". FAC-501-WECC-1 R2 has been revised. Mapping document not available in WECC/NERC sites.	TO	Docket No. RD18-5-000, Issued May 30, 2018	30 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval US Enforcement Date: 01 Jul 2018	No impact on DP	No cost	No cost	NA
FAC-501-WECC-2 R3	Name: Transmission Maintenance Description: To ensure the Transmission Owner of a transmission path identified in Attachment B, Major WECC Transfer Paths in the Bulk Electric System, including associated facilities has a Transmission Maintenance and Inspection Plan (TMIP), and performs and documents maintenance and inspection activities in accordance with the TMIP.	FAC-501-WECC-1 (see Assessment Report 5)	2 - No major change to this requirement, language modification - i.e. "implement and follow" has been replaced with "adhere" Mapping document not available in WECC/NERC sites.	TO	Docket No. RD18-5-000, Issued May 30, 2018	30 May 18	Implementation Time: First day of the first quarter following applicable regulatory approval US Enforcement Date: 01 Jul 2018	No impact on DP	No cost	No cost	NA
PER-003-2 R1	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 (see Assessment Report 6) and PER-004-2 (see Assessment Report 5)	2 - No material change to this requirement apart from a footnote reference to clarify that the reference to "NERC Reliability Operator" certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification Program Manual. Mapping document not available.	RC	Docket No. RD18-9-000, Issued November 21, 2018	21 Nov 18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval US Enforcement Date: 01 July 2019	No impact on DP	No cost	No cost	NA
PER-003-2 R2	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 (see Assessment Report 6) and PER-004-2 (see Assessment Report 5)	2 - No material change to this requirement apart from a footnote reference to clarify that the reference to "NERC Reliability Operator" certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification Program Manual. Mapping document not available.	TO	Docket No. RD18-9-000, Issued November 21, 2018	21 Nov 18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval US Enforcement Date: 01 July 2019	No impact on DP	No cost	No cost	NA
PER-003-2 R3	Name: Operating Personnel Credentials Description: To ensure that System Operators performing the reliability-related tasks of the Reliability Coordinator, Balancing Authority and Transmission Operator are certified through the NERC System Operator Certification Program when filling a Realtime operating position responsible for control of the Bulk Electric System.	PER-003-1 (see Assessment Report 6) and PER-004-2 (see Assessment Report 5)	2 - No material change to this requirement apart from a footnote reference to clarify that the reference to "NERC Reliability Operator" certificate within the requirement pertains to those certificates identified in the NERC System Operator Certification Program Manual. Mapping document not available.	BA	Docket No. RD18-9-000, Issued November 21, 2018	21 Nov 18	Implementation Time: First day of the first quarter that is six (6) months following applicable regulatory approval US Enforcement Date: 01 July 2019	No impact on DP	No cost	No cost	NA
PER-006-1 R1	Name: Specific Training for Personnel Description: To ensure that personnel are trained on specific topics essential to reliability to perform or support Real-time operations of the Bulk Electric System.	PRC-001-1.1(f) (see Assessment Report 9)	1 - New standard. PER-006-1 R1 replaces PRC-001-1.1(f) RL; also the referenced term Special Protection System (SPS) has been replaced with Remedial Action Scheme (RAS). PRC-001-1(f) to PER-006-1 Mapping Document	GCP	Docket No. RM16-12-000, Order No. Issued June 7, 2018	13 Aug 2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval US Enforcement Date: 01 Oct 2020	No impact on DP	No cost	No cost	NA

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (S) (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 (S)	Cost Ongoing (S)	
PRC-005-2-R1	Name: Generator Relay Loadability Description: To set load-responsive protective relays associated with generation facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	PRC-005-1 (see Assessment Report 8)	2. Provides clarification for specific facility applications and load-responsive protective relays; LV protection devices that do not have adjustable settings is included in the Relay settings inclusion; provided alternative loadability Options for Table 1 specific to dispersed power producing resources; eliminated the term "pickup" in Table 1 to better align with the intent of the standard for relays to "hot trip", and provided clarity on few miscellaneous items.	GO, TO, DP	Docket No. RP18-6-000, Issue Date: May 2, 2018	2-May-2018	Implementation Time: First day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard. Initial compliance is as follows: Except for other standards, evaluation criteria address 5a, 5b, 2a, 2b, 2c, 5a, 5b, 6a, 6b, 6c, 11, 13a, 13b, 14a, 14b, 14c, and 14d. If the functional entity determines that replacement or removal of load-responsive protective relay is not necessary later of October 1, 2018 or 12 months after the effective date, if the functional entity determines that replacement or removal of load-responsive protective relay is necessary, later of October 1, 2021 or 36 months after the effective date. For Options 2a, 14a, 14b, and 14c, if the functional entity determines that replacement or removal of load-responsive protective relay is not necessary, 24 months after the effective date. If the functional entity determines that replacement is necessary, 48 months after the effective date. For Options 2b, 2c, 5a, 5b, 2a, 2b, 2c, 5a, 5b, 6a, 6b, 6c, 11, 13a, and 13b, if the functional entity determines that replacement of load-responsive protective relay is not necessary, 36 months after the effective date. If the functional entity determines that replacement is necessary, 60 months after the effective date. US Enforcement Date: 01-Jul-2018	Need verification of the relay settings on generator protection relays and GSI transformer protection relays to see if we are in compliance with this standard	30,000	No cost	6 month from the implementation of this standard by BCUC
			Mapping Document not available								
PRC-007-1-R1	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(I) (see Assessment Report 9)	1. New standard. Incorporates reliability objectives of PRC-001-1.1(I) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1 R2 mandates an entity periodically perform Protection System Coordination Studies and/or compare existing Fault current values to established Fault current baselines for Protection Systems applied on BES Elements that are identified as being affected by changes in Fault current.	TO, GO, DP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Review of Short Circuit model will need to be done, plus verifications of the protection settings to be completed	30,000	No cost	6 months from the implementation of the standard by BCUC
			PRC-001-1(I) to PRC-027-1 Mapping Document								
PRC-007-1-R2	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(I) (see Assessment Report 9)	1. New standard. Incorporates reliability objectives of PRC-001-1.1(I) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1 R2 mandates an entity to establish a process for developing and maintaining Protection System settings for BES Elements to operate in the intended sequence during Faults.	TO, GO, DP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Review of Short Circuit model will need to be done, plus verifications of the protection settings to be completed	30,000	No cost	6 months from the implementation of the standard by BCUC
			PRC-001-1(I) to PRC-027-1 Mapping Document								
PRC-007-1-R3	Name: Coordination of Protection Systems for Performance During Faults Description: 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-001-1.1(I) (see Assessment Report 9)	1. New standard. Incorporates reliability objectives of PRC-001-1.1(I) R3 and R4, clarifies the coordination aspects, applicability changed to GO, TO and DP, and includes additional requirements; PRC-027-1 R3 mandates that an entity utilize the process established in accordance with PRC-027-1 R1.	TO, GO, DP	Docket No. RM18-22-000, Order No. 847, Issued June 7, 2018	13-Aug-2018	Implementation Time: First day of the first calendar quarter that is twenty-four (24) months following applicable regulatory approval. US Enforcement Date: 01-Oct-2020	Review of Short Circuit model will need to be done, plus verifications of the protection settings to be completed	30,000	No cost	6 months from the implementation of the standard by BCUC
			PRC-001-1(I) to PRC-027-1 Mapping Document								
VAR-001-S-R1	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; minor format changes to standard.	TOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								
VAR-001-S-R2	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; minor format changes to standard.	TOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								
VAR-001-S-R3	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; minor format changes to standard.	TOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								
VAR-001-S-E-A-14	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; minor format changes to standard.	TOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								
VAR-001-S-E-A-13	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. No changes to requirement; measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and otherwise, minor format changes.	TOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								
VAR-001-S-E-A-14	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. In E.A.14 "Area" was changed to "area"; measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and otherwise minor format changes.	TOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								
VAR-001-S-E-A-15	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5. This requirement is the same as VAR-001-4.2 E.A.15 (no change to requirement); previous VAR-001-4.2 E.A.15 and associated elements were deleted because the task is contained in VAR-002-4.3, Generator Operation for Maintaining Network Voltage Schedules, Requirement R2, Part 2.3 as a lesser included task. Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes.	GOP	Docket No. RP18-6-000, Issued October 15, 2018	15-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	NA
			No mapping document available.								

FERC Approved New/Revised/Retired Standard/Requirement (Hyperlinks to the Standard and RSAs)	Standard Name and Description	Current BCLUC Adopted Standards to be Superseded (Indicate associated Assessment Report feedback spreadsheets)	FERC Approved Revision (Hyperlinks to the mapping document)	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/Sustainability Impact (Press Alt-Enter to insert a carriage return in a cell)	Estimated Incremental/New Costs Associated with Revision/New Standard/Requirement, if any (\$) (Press Alt-Enter to insert a carriage return in a cell)		BCLUC Implementation Time (Press Alt-Enter to insert a carriage return in a cell)
									Cost One Time (\$)	Cost Ongoing (\$)	
VAR-001-S-E-A-16	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- This requirement is the same as VAR-001-4.2 C.A.17 (no change to requirements). Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	TOP	Docket No. SR18-8-000, Issued October 16, 2018	16-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	N/A
VAR-001-S-E-A-17	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	VAR-001-4.2 (see Assessment Report 11)	5- This requirement is the same as VAR-001-4.2 C.A.18 (no change to requirements). Otherwise, measures were updated and relocated matching current NERC conventions, replacing "shall" with "will" and other minor format changes. No mapping document available.	GOP	Docket No. SR18-8-000, Issued October 16, 2018	16-Oct-2018	Implementation Time: First day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority. US Enforcement Date: 01-Jan-2019	No impact on DP	No cost	No cost	N/A
VAR-002-WFCC-2 (entire standard)	Name: Voltage and Reactive Control Description: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.	N/A/Retired standard (see Assessment Report 9)	N/A Retired standard	GO, TOP,	Docket No. RD18-1-000, Issued September 5, 2018	5-Sep-2018	No Implementation time required. Retired standard US Inactive Date: Sep-5-2018	No impact on DP	No cost	No cost	N/A

Disclaimer: This information has been prepared as input into BC Hydro's twelfth 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, DP, etc.):

FERC Approved New/Revised/Retired NERC Glossary of Terms from the October 6, 2017 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 06, 2017 Glossary of Terms	Current BCUC Adopted Definition from October 06, 2017 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 Organizational Activities and Reliability/Suitability Impact (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 (\$)	
Operational Planning Analysis *Glossary term is specific to the new PGR-006-1 standard in addition to the currently adopted RO-008-1 standard.	OPA	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.)	Operational Planning Analysis (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020				
Protection System Coordination Study *Glossary term is specific to the new PRC-027-1 standard.		An analysis to determine whether Protection Systems operate in the intended sequence during Faults.	New	N/A	7-Jun-2018	1-Oct-2020				
Real-time Assessment *Glossary term is specific to the new PGR-006-1 standard in addition to the currently adopted RO-008-1 standard.	RTA	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.)	Real-time Assessment (see Assessment Report 9)	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.)	7-Jun-2018	1-Oct-2020				
Removable Media *Glossary term is specific to the revised CP-003-7 standard in addition to the currently adopted CP-010-2 standard.		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.	Removable Media (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020				
Transient Cyber Asset *Glossary term is specific to the revised CP-003-7 standard in addition to the currently adopted CP-010-2 standard.	TCA	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.	Transient Cyber Asset (see Assessment Report 10)	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.	19-Apr-2018	1-Jan-2020				

Mandatory Reliability Standards Assessment Report No. 12

Appendix D

Draft Order



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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 Assessment Report No. 12

BEFORE:

Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

- A. On May 1, 2019, the British Columbia Hydro and Power Authority (BC Hydro) filed Mandatory Reliability Standards (MRS) Assessment Report No. 12 (Report No. 12) with the British Columbia Utilities Commission (BCUC), assessing two new standards and eleven revised standards (collectively, Revised Standards) and two retired standards (Retired Standards) developed by the North American Electric Reliability Corporation (NERC) and/or the Western Electricity Coordinating Council (WECC). In MRS Report No. 12, BC Hydro has assessed reliability standards that were Federal Energy Regulatory Commission (FERC) approved with an effective order within the period between, and including, December 1, 2017 and November 30, 2018; BC Hydro assessed the reliability standards and if adopted, the 13 Revised Standards would supersede existing reliability standards previously adopted by the Commission;
- B. The Revised Standards assessed by BC Hydro in MRS Report No. 12 are based on defined terms contained in the NERC Glossary of Terms Used in Reliability Standards dated July 3, 2018 (NERC Glossary). In addition, BC Hydro assessed one new and four revised defined terms (Revised Terms) contained in the NERC Glossary. MRS Report No. 12 recommends the five Revised Terms be adopted by the BCUC as they will preserve or enhance the reliability of the Bulk Electric System in British Columbia (BC), and thus serve the public interest;
- C. In MRS Report No. 12, BC Hydro recommends that all 13 Revised Standards and all five Revised Terms are suitable for adoption in BC at this time. In addition, BC Hydro recommends two Retired Standards are suitable for retirement in BC;

- D. BC Hydro recommends that, in connection with the adoption of CIP-003-7 and PRC-025-2, B.C.-specific versions of the FERC approved related Implementation Plans be adopted in BC BC Hydro provided B.C.-specific versions of the CIP-003-7 and PRC-025-2 Implementation Plans as part of the Report for the BCUC's consideration;
- E. By Order R-XX-19 dated MMM DD, 2019, BC Hydro was directed to publish a notice of process for MRS Report No. 12 and the Regulatory Timetable was established for public comment;
- F. On MMM DD, 2019, comments were received from xxxxxx;
- G. Although not assessed by BC Hydro, the BCUC considers that the Compliance Provisions of the reliability standards should be adopted to maintain compliance monitoring consistency with other jurisdictions that have adopted the reliability standards with the Compliance Provisions. The BCUC finds it appropriate to provide effective dates for B.C. entities to come into compliance with the Revised Standards and Revised Terms adopted in this order;
- H. Pursuant to section 125.2(6) of the *Utilities Commission Act*, the BCUC must adopt the reliability standards addressed in MRS Report No. 12 if the BCUC considers that the reliability standards are required to maintain or achieve consistency in BC with other jurisdictions that have adopted the reliability standards; and
- I. The BCUC has reviewed and considered MRS Report No. 12, the Revised Standards, Retired Standards and Revised Terms assessed therein, and the comments received from entities and considers that the adoption of the recommendations in MRS Report No. 12 is warranted.

NOW THEREFORE pursuant to section 125.2 of the *Utilities Commission Act*, which 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. The 13 Revised Standards assessed in MRS Report No. 12 are adopted with effective dates in Table 1 of Attachment A to this order and each standard to be superseded by a Revised Standard adopted in this order shall remain in effect until the effective date of the Revised Standard superseding it.
- 2. All reliability standards listed in Attachment B to this order are in effect in BC as of the dates shown. The effective dates for the reliability standards listed in Attachment B supersede the effective dates that were included in any similar list appended to any previous order. Attachment B to this order also includes those reliability standards with retirement/effective dates held in abeyance to be assessed at a later date.
- 3. Individual requirements within reliability standards that incorporate, by reference, reliability standards that have not been adopted by the 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.
- 4. The NERC Glossary of Terms used in reliability standards, dated July 3, 2018, is adopted to define terms employed in the reliability standards. The effective date of each of the new or Revised Terms adopted and the date of each Retired Term is the date in Table 2 of Attachment A to this order. Each glossary term to be superseded by a Revised Term adopted in this order shall remain in effect until the effective date of the Revised Term superseding it.

5. The Revised Terms listed in Attachment C to this order are in effect in BC as of the effective dates indicated. The effective dates for the Revised Terms listed in Attachment C supersede the effective dates that were included in any similar list appended to any previous order. Other terms in the NERC Glossary, which do not include a United States FERC approval date on or before November 30, 2018, are of no force or effect in B.C.
6. 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.
7. The B.C.-specific versions of the CIP-003-7 and PRC-025-2 Implementation Plans are adopted in the form directed by the BCUC and as amended from time to time, and effective in B.C. as indicated in Attachment D to this order. The B.C.-specific versions of the CIP-003-7 and PRC-025-2 Implementation Plans will be posted on the WECC website with links from the BCUC website.
8. The Revised Standards in their written form are adopted as set out in Attachment E to this order.
9. The reliability standards adopted in B.C. will be posted on the WECC website with a link from the BCUC website.
10. Entities subject to Mandatory Reliability Standards are not required to report to NERC or FERC, but may do so on a voluntary basis.

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

Attachment Options

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

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded¹
1.	BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	First day of the first calendar quarter, six months after BCUC adoption.	Revised	BAL-002-2
2.	BAL-004-0	Time Error Correction	Retire immediately after BCUC approval.	Retired	N/A-Retired standard
3.	BAL-004-WECC-3	Automatic Time Error Correction	First day of the second calendar quarter after BCUC adoption.	Revised	BAL-004-WECC-2
4.	CIP-003-7	Cyber Security — Security Management Controls	First day of the first calendar quarter after BCUC adoption. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C. specific version of the CIP-003-7 Implementation Plan be implemented in B.C pursuant to an order of the BCUC providing for the administration of adopted reliability standards.	Revised	CIP-003-5
5.	EOP-004-4	Event Reporting	First day of the first calendar quarter, twelve months after BCUC adoption.	Revised	EOP-004-3
6.	EOP-005-3	System Restoration from Blackstart Resources	First day of the first calendar quarter, twelve months after BCUC adoption.	Revised	EOP-005-2
7.	EOP-006-3	System Restoration Coordination	First day of the first calendar quarter, twelve months after BCUC adoption.	Revised	EOP-006-2
8.	EOP-008-2	Loss of Control Center Functionality	First day of the first calendar quarter, twelve months after BCUC adoption.	Revised	EOP-008-1
9.	FAC-501-WECC-2	Transmission Maintenance	First day of the first calendar quarter after BCUC adoption.	Revised	FAC-501-WECC-1
10.	PER-003-2	Operating Personnel Credentials	First day of the first calendar quarter, six months after BCUC adoption.	Revised	PER-003-1 and PER-004-2

¹ BCUC approved reliability standard to be superseded by the replacement or revised reliability standard assessed.

Appendix D - Attachment A

	Standard	Standard Name	Effective Date	Type	BCUC Approved Standard(s) Being Superseded¹
11.	PER-006-1	Specific Training for Personnel	First day of the first calendar quarter, twenty-four months after BCUC adoption.	New	PRC-001-1.1(ii) Requirement R1
12.	PRC-025-2	Generator Relay Loadability	First day of the first calendar quarter after BCUC adoption. In connection with the recommendation to adopt the standard, BC Hydro recommends that a B.C. specific version of the PRC-025-2 Implementation Plan be implemented in B.C pursuant to an order of the BCUC providing for the administration of adopted reliability standards.	Revised	PRC-025-1
13.	PRC-027-1	Coordination of Protection Systems for Performance During Faults	First day of the first calendar quarter, twenty-four months after BCUC adoption.	New	PRC-001-1.1(ii) Requirements R3 & R4
14	VAR-001-5	Voltage and Reactive Control	First day of the first calendar quarter after BCUC adoption.	Revised	VAR-001-4.2
15	VAR-002-WECC-2	Voltage and Reactive Control	Retire immediately after BCUC approval.	Retired	N/A-Retired standard

**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	Operational Planning Analysis *Glossary term is specific to the new PER-006-1 standard in addition to the currently adopted IRO-008-1 standard.	OPA	Coincide with effective date of PER-006-1 standard after BCUC adoption.	Operational Planning Analysis
2	Protection System Coordination Study *Glossary term is specific to the new PRC-027-1 standard.		Coincide with effective date of PRC-027-1 standard after BCUC adoption.	New
3	Real-time Assessment *Glossary term is specific to the new PER-006-1 standard in addition to the currently adopted IRO-008-1 standard.	RTA	Coincide with effective date of PER-006-1 standard after BCUC adoption.	Real-time Assessment
4	Removable Media *Glossary term is specific to the revised CIP-003-7 standard in addition to the currently adopted CIP-010-2 standard.		Coincide with effective date of CIP-003-7 standard after BCUC adoption.	Removable Media
5	Transient Cyber Asset *Glossary term is specific to the revised CIP-003-7 standard in addition to the currently adopted CIP-010-2 standard.	TCA	Coincide with effective date of CIP-003-7 standard after BCUC adoption.	Transient Cyber Asset

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-002-2 ¹	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event	R-39-17	January 1, 2018
BAL-002-3	Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event		
BAL-002-WECC-2a	Contingency Reserve	R-39-17	July 26, 2017
BAL-003-1.1	Frequency Response and Frequency Bias Setting	R-32-16A	October 1, 2016
~~BAL-004-0~~	~~Time Error Correction~~	~~G-67-09~~	~~November 1, 2010~~
BAL-004-WECC-2 ¹	Automatic Time Error Correction	R-32-14	October 1, 2014
BAL-004-WECC-3	Automatic Time Error Correction		
BAL-005-0.2b ¹	Automatic Generation Control	R-41-13	December 12, 2013 R2: Retired January 21, 2014 ²
BAL-005-1	Balancing Authority Control	R-33-18	October 1, 2019
BAL-006-2 ³	Inadvertent Interchange	R-1-13	April 15, 2013
CIP-002-5.1a	Cyber Security — BES Cyber System Categorization	R-33-18	October 1, 2018
CIP-003-5 ¹	Cyber Security – Security Management Controls	R-38-15	October 1, 2018 R2.2, R2.3: Adoption held in abeyance pending the adoption of CIP-003-7
CIP-003-6 ¹	Cyber Security — Security Management Controls	n/a	Adoption held in abeyance at this time ⁴
CIP-003-7	Cyber Security — Security Management Controls		
CIP-004-6	Cyber Security — Personnel & Training	R-39-17	October 1, 2018

¹ Reliability standard is superseded by the revised/replacement reliability standard listed immediately below it as of the effective date(s) of the revised/replacement reliability standard.

² On November 21, 2013, FERC Order 788 (referred to as Paragraph 81) approved the retiring of the reliability standard requirements.

³ Reliability standard is superseded by BAL-005-1 as of the BAL-005-1 effective date

⁴ BC Hydro recommends that the CIP-003-6 reliability standard be held in abeyance and be of no force or effect in B.C. due to technical suitability issues that will not improve reliability and instead place undue burden on responsible entities. CIP-003-7 has been assessed under MRS Assessment Report (Report No. 12) which will supersede CIP-003-6.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
CIP-005-5	Cyber Security – Electronic Security Perimeter(s)	R-38-15	October 1, 2018
CIP-006-6	Cyber Security — Physical Security of BES Cyber Systems	R-39-17	October 1, 2018
CIP-007-6	Cyber Security — System Security Management	R-39-17	October 1, 2018
CIP-008-5	Cyber Security – Incident Reporting and Response Planning	R-38-15	October 1, 2018
CIP-009-6	Cyber Security — Recovery Plans for BES Cyber Systems	R-39-17	October 1, 2018
CIP-010-2	Cyber Security – Configuration Change Management and Vulnerability Assessments	R-39-17	October 1, 2018
CIP-011-2	Cyber Security – Information Protection	R-39-17	October 1, 2018
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
EOP-003-1 ⁵	Load Shedding Plans	G-67-09	November 1, 2010
EOP-003-2 ⁶	Load Shedding Plans	n/a	Adoption held in abeyance at this time ⁷
EOP-004-3 ¹	Event Reporting	R-39-17	October 1, 2017
EOP-004-4	Event Reporting		
EOP-005-2 ¹	System Restoration and Blackstart Resources	R-32-14	August 1, 2015 R3.1: Retired January 21, 2014 ²
EOP-005-3	System Restoration and Blackstart Resources		
EOP-006-2 ¹	System Restoration Coordination	R-32-14	August 1, 2014
EOP-006-3	System Restoration Coordination		
EOP-008-1 ¹	Loss of Control Center Functionality	R-32-14	August 1, 2015

⁵ Reliability standard would be superseded by EOP-003-2 if adopted in B.C. Adoption of EOP-003-2 pending reassessment.

⁶ Reliability standard is superseded by EOP-011-1 as of the EOP-011-1 effective date in conjunction with PRC-010-2 Requirement 1 if adopted in B.C. Adoption of PRC-010-2 pending reassessment.

⁷ Unable to assess based on undefined Planning Coordinator/Planning Authority footprints and entities responsible. The BCUC Reasons for Decision for Order No. R-41-13 (page 20), indicated that a separate process would be established to consider this matter as it pertains to B.C.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
EOP-008-2	Loss of Control Center Functionality		
EOP-010-1 ⁸	Geomagnetic Disturbance Operations	R-38-15	R1, R3: October 1, 2016 R2: At retirement of IRO-005-3.1a R3
EOP-011-1	Emergency Operations	R-39-17	October 1, 2018
FAC-001-2 ¹	Facility Interconnection Requirements	R-38-15	October 1, 2016
FAC-001-3	Facility Interconnection Requirements	R-33-18	October 1, 2019
FAC-002-2	Facility Interconnection Studies	R-38-15	October 1, 2015
FAC-003-4	Transmission Vegetation Management	R-39-17	October 1, 2017
FAC-008-3	Facility Ratings	R-32-14	August 1, 2015 R4 and R5: Retired January 21, 2014 ²
FAC-010-3	System Operating Limits Methodology for the Planning Horizon	R-39-17	R1–R4: October 1, 2017 R5: Retired
FAC-011-3	System Operating Limits Methodology for the Operations Horizon	R-39-17	October 1, 2017
FAC-013-1 ⁹	Establish and Communicate Transfer Capability	G-67-09	November 1, 2010
FAC-013-2	Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon	n/a	Adoption held in abeyance at this time ⁷
FAC-014-2	Establish and Communicate System Operating Limits	G-167-10	January 1, 2011
FAC-501-WECC-1 ¹	Transmission Maintenance	R-1-13	April 15, 2013
FAC-501-WECC-2	Transmission Maintenance		
INT-004-3.1	Dynamic Transfers	R-38-15	R1, R2: October 1, 2015 R3: January 1, 2016
INT-006-4	Evaluation of Interchange Transactions	R-38-15	October 1, 2015
INT-009-2.1	Implementation of Interchange	R-38-15	October 1, 2015

⁸ Requirement 2 of the reliability standard will be effective upon the retirement of IRO-005-3.1a Requirement 3 which follows the effective date of IRO-002-4 (October 1, 2017; per BCUC Order No. R-39-17).

⁹ Reliability standard would be superseded by the FAC-013-2 if adopted in B.C. Adoption of FAC-013-2 pending reassessment.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
INT-010-2.1	Interchange Initiation and Modification for Reliability	R-38-15	October 1, 2015
INT-011-1.1	Intra-Balancing Authority Transaction Identification	R-38-15	October 1, 2015
IRO-001-4	Reliability Coordination – Responsibilities	R-39-17	October 1, 2017
IRO-002-2 ¹⁰	Reliability Coordination – Facilities	R-1-13	April 15, 2013
IRO-002-5	Reliability Coordination – Monitoring and Analysis	R-33-18	January 1, 2019
IRO-005-3.1a ^{10,11}	Reliability Coordination - Current Day Operations	R-32-14	August 1, 2014
IRO-006-5	Reliability Coordination – Transmission Loading Relief	R-1-13	April 15, 2013
IRO-006-WECC-2	Qualified Transfer Path Unscheduled Flow (USF) Relief	R-38-15	October 1, 2015
IRO-008-2	Reliability Coordinator Operational Analyses and Real-time Assessments	R-39-17	October 1, 2017
IRO-009-2	Reliability Coordinator Actions to Operate Within IROLs	R-39-17	October 1, 2017
IRO-010-2	Reliability Coordinator Data Specification and Collection	R-39-17	April 1, 2019
IRO-014-3	Coordination Among Reliability Coordinators	R-39-17	October 1, 2017
IRO-015-1 ¹⁰	Notification and Information Exchange	G-67-09	November 1, 2010
IRO-017-1	Outage Coordination	R-39-17	October 1, 2020
IRO-018-1 ¹¹	Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities	R-39-17	April 1, 2018
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

¹⁰ Refer to “IRO and TOP Reliability Standards Supersession Mapping” section below.

¹¹ Requirement 3 of the reliability standard is superseded by EOP-010-1 Requirement 2 as of the IRO-002-4 effective date (October 1, 2017; per BCUC Order No. R-39-17).

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
MOD-008-1	Transmission Reliability Margin Calculation Methodology	G-175-11	November 30, 2011
MOD-010-0 ¹²	Steady-State Data for Modeling and Simulation for the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-012-0 ¹²	Dynamics Data for Modeling and Simulation of the Interconnected Transmission System	G-67-09	November 1, 2010
MOD-020-0	Providing Interruptible Demands and Direct Control Load management Data to System Operators and Reliability Coordinators	G-67-09	November 1, 2010
MOD-025-2	Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
MOD-026-1	Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R6: October 1, 2015
MOD-027-1	Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions	R-38-15	R1: October 1, 2016 R2: 30% by October 1, 2019 50% by October 1, 2021 100% by October 1, 2025 R3-R5: October 1, 2015
MOD-028-2	Area Interchange Methodology	R-32-14	August 1, 2014
MOD-029-2a	Rated System Path Methodology	R-39-17	October 1, 2017
MOD-030-3	Flowgate Methodology	R-39-17	October 1, 2017
MOD-031-2	Demand and Energy Data	R-39-17	April 1, 2018
MOD-032-1	Data for Power System Modeling and Analysis	R-38-15	Effective date held in abeyance ⁷
MOD-033-1	Steady-State and Dynamic System Model Validation	R-38-15	Effective date held in abeyance ⁷
NUC-001-3	Nuclear Plant Interface Coordination	R-38-15	January 1, 2016

¹² Reliability standard will be superseded by MOD-032-1 and MOD-033-1 if adopted in B.C. Adoption of MOD-032-1 and MOD-033-1 pending reassessment.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
PER-001-0.2 ¹⁰	Operating Personnel Responsibility and Authority	R-41-13	December 12, 2013
PER-002-0	Operating Personnel Training	G-67-09	November 1, 2010
PER-003-1 ¹¹	Operating Personnel Credentials	R-41-13	January 1, 2015
PER-003-2	Operating Personnel Credentials		
PER-004-2 ¹³	Reliability Coordination – Staffing	R-1-13	January 15, 2013
PER-005-2	Operations Personnel Training	R-38-15	R1-R4, R6: October 1, 2016 R5: October 1, 2017
PER-006-1 ¹⁴	Specific Training for Personnel		
PRC-001-1.1(ii) ¹⁵	System Protection Coordination	R-32-16A	October 1, 2016
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
PRC-005-1.1b ^{1, 18}	Transmission and Generation Protection System Maintenance and Testing	R-32-14	January 1, 2015
PRC-005-2 ¹	Protection System Maintenance	R-38-15	R1, R2, R5: October 1, 2017 R3, R4: staged as per B.C.-specific Implementation Plan
PRC-005-2(i) ¹	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-006-2 ^{1,16}	Automatic Underfrequency Load Shedding	n/a	Adoption held in abeyance at this time ⁷

¹³ Reliability standard will be superseded by PER-003-2 if adopted in B.C. as of the PER-003-2 effective date.

¹⁴ Reliability standard will supersede PRC-001-1.1(ii) R1 as of the effective date of PER-006-1.

¹⁵ 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(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) will be superseded by other reliability standards as of October 1, 2020.

¹⁶ Reliability standard supersedes PRC-006-1 which has been held in abeyance due to the undefined Planning Coordinator/Planning Authority footprints and entities responsible.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
PRC-006-3	Automatic Underfrequency Load Shedding	n/a	Adoption held in abeyance at this time ⁷
PRC-007-0 ¹⁷	Assuring consistency of entity Underfrequency Load Shedding Program Requirements	G-67-09	November 1, 2010
PRC-008-0 ¹⁸	Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program	G-67-09	November 1, 2010
PRC-009-0 ¹⁷	Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event	G-67-09	November 1, 2010
PRC-010-0 ¹	Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program	G-67-09	November 1, 2010 R2: Retired January 21, 2014 ²
PRC-010-2	Under Voltage Load Shedding	n/a	Adoption held in abeyance at this time ⁷
PRC-011-0 ¹⁸	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) to be determined. Unable to be assessed at this time. ⁷ R2: Attachment 2, Section I Parts 7(d) and 7(e) to be determined. Unable to be assessed at this time. ⁷ R4: To be determined. Unable to be assessed at this time. ⁷
PRC-015-1 ¹⁹	Remedial Action Scheme Data and Documentation	R-39-17	October 1, 2017
PRC-016-1 ¹⁹	Remedial Action Scheme Misoperations	R-39-17	October 1, 2017
PRC-017-1 ¹⁸	Remedial Action Scheme Maintenance and Testing	R-39-17	October 1, 2017
PRC-018-1 ²⁰	Disturbance Monitoring Equipment Installation and Data Reporting	G-67-09	November 1, 2010

¹⁷ Reliability standard will be superseded by PRC-006-2 if adopted in B.C. Adoption of PRC-006-2 pending reassessment.

¹⁸ Reliability standard is superseded by PRC-005-6 as per the PRC-005-6 B.C.-specific Implementation Plan.

¹⁹ Reliability standard is superseded by PRC-012-2 as of the PRC-012-2 effective date.

²⁰ Reliability standard is superseded by PRC-002-2 as of the PRC-002-2 effective date.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection	R-32-16A	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-021-1 ²¹	Under Voltage Load Shedding Program Data	G-67-09	November 1, 2010
PRC-022-1 ²¹	Under Voltage Load Shedding Program Performance	G-67-09	November 1, 2010 R2: Retired January 21, 2014 ²
PRC-023-2 ^{1, 22}	Transmission Relay Loadability	R-41-13	R1-R5: For circuits identified by sections 4.2.1.1 and 4.2.1.4: January 1, 2016 For circuits identified by sections 4.2.1.2, 4.2.1.3, 4.2.1.5, and 4.2.1.6: To be determined ⁷ R6: To be determined ⁷
PRC-023-4	Transmission Relay Loadability	R-39-17	R1-R5 Circuits 4.2.1.1, 4.2.1.4: October 1, 2017 with the exception Criterion 6 of R1 which will not become effective until PRC-025-1 R 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: To be determined
PRC-024-2	Generator Frequency and Voltage Protective Relay Settings	R-32-16A	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-025-1 ¹	Generator Relay Loadability	R-38-15	40% by October 1, 2017 60% by October 1, 2018 80% by October 1, 2019 100% by October 1, 2020
PRC-025-2	Generator Relay Loadability		
PRC-026-1	Relay Performance During Stable Power Swings	n/a	Adoption held in abeyance at this time ⁷

²¹ Reliability standard is superseded by PRC-010-2 if adopted in B.C. Adoption of PRC-010-2 pending reassessment.

²² PRC-023-2 Requirement 1, Criterion 6 only is superseded by PRC-025-1 as of PRC-025-1's 100 per cent Effective Date.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
PRC-027-1 ²³	Coordination of Protection Systems for Performance During Faults		
TOP-001-1a ¹⁰	Reliability Responsibilities and Authorities	R-1-13	January 15, 2013
TOP-001-4	Transmission Operations	R-33-18	October 1, 2020
TOP-002-2.1b ¹⁰	Normal Operations Planning	R-41-13	December 12, 2013
TOP-002-4	Operations Planning	R-39-17	October 1, 2020
TOP-003-1 ¹⁰	Planned Outage Coordination	R-1-13	April 15, 2013
TOP-003-3	Operational Reliability Data	R-39-17	April 1, 2019
TOP-004-2 ¹⁰	Transmission Operations	G-167-10	January 1, 2011
TOP-005-2a ¹⁰	Operational Reliability Information	R-1-13	April 15, 2013
TOP-006-2 ¹⁰	Monitoring System Conditions	R-1-13	April 15, 2013
TOP-007-0 ¹⁰	Reporting System Operating Unit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	G-67-09	November 1, 2010
TOP-008-1 ¹⁰	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	October 1, 2020
TPL-001-0.1 ²⁴	System Performance Under Normal (No Contingency) Conditions (Category A)	G-167-10	January 1, 2011
TPL-001-4	Transmission System Planning Performance Requirements	R-27-18A	R1: July 1, 2019 R2-R6, R8: July 1, 2020 R7: To be determined ⁷
TPL-002-0b ²⁴	System Performance Following Loss of a Single Bulk Electric System Element (Category B)	R-1-13	January 15, 2013
TPL-003-0b ²⁴	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)	R-32-14	August 1, 2014
TPL-004-0a ²⁴	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)	R-32-14	August 1, 2014

²³ Reliability standard will supersede PRC-001-1.1(ii) Requirements 3 and 4 as of the effective date of PRC-027-1.

²⁴ Reliability standard is superseded by TPL-001-4 Requirements 2 to 6, and 8 as of their effective dates.

B.C. Reliability Standards

Standard	Name	BCUC Order Adopting	Effective Date
TPL-007-1	Transmission System Planned Performance for Geomagnetic Disturbance Events	n/a	Adoption held in abeyance at this time ⁷
VAR-001-4.2 ¹	Voltage and Reactive Control	R-33-18	October 1, 2018
VAR-001-5	Voltage and Reactive Control		
VAR-002-4.1	Generator Operation for Maintaining Network Voltage Schedules	R-33-18	October 1, 2018
~~VAR-002-WECC-2~~	~~Automatic Voltage Regulators (AVR)~~	~~R-32-16A~~	~~October 1, 2016~~
VAR-501-WECC-2 ¹	Power System Stabilizer (PSS)	R-32-16A	October 1, 2016
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 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, TOP, and PER reliability standards by the revised/replacement IRO and TOP reliability standards adopted or yet to be adopted in B.C. as of the effective date in the “B.C. Reliability Standards” section above:

IRO-002-2 — Reliability Coordination - Facilities

IRO-005-3.1a — Reliability Coordination - Current Day Operations

IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators

PER-001-0.2 — Operating Personnel Responsibility and Authority

TOP-001-1a — Reliability Responsibilities and Authorities

TOP-002-2.1b — Normal Operations Planning

TOP-003-1 — Planned Outage Coordination

TOP-004-2 — Transmission Operations

TOP-005-2a — Operational Reliability Information

TOP-006-2 — Monitoring System Conditions

TOP-007-0 — Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

TOP-008-1 — Response to Transmission Limit Violations

IRO and TOP Reliability Standards Supersession Mapping

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

Standard IRO-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

IRO and TOP Reliability Standards Supersession Mapping

Standard IRO-005-3.1a — Reliability Coordination - Current Day Operations	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
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 IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
Requirements R1 and R2	IRO-014-3
Requirement R3	IRO-010-2

Standard PER-001-0.2 — Operating Personnel Responsibility and Authority	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
All Requirements	TOP-001-4

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

IRO and TOP Reliability Standards Supersession Mapping

Standard TOP-001-1a — Reliability Responsibilities and Authorities	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
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-002-2.1b — Normal Operations Planning	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
Requirement R1	TOP-001-4 TOP-002-4
Requirements R2, R5-R9, R12	TOP-002-4
Requirement R3	IRO-017-1 TOP-003-3
Requirement R4	IRO-017-1 IRO-008-2

IRO and TOP Reliability Standards Supersession Mapping

Requirement R10	IRO-017-1 TOP-001-4 TOP-002-4 TOP-003-3
Requirement R11	TOP-001-4 TOP-002-4
Requirement R13	TOP-001-4 TOP-003-3
Requirements R14, R15, and R19	TOP-003-3
Requirements R16, R17, and R18	IRO-010-2

IRO and TOP Reliability Standards Supersession Mapping

Standard TOP-003-1 — Planned Outage Coordination	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
Requirement R1	IRO-010-2 TOP-003-3
Requirement R2	IRO-017-1 TOP-003-3
Requirement R3	TOP-001-4
Requirement R4	IRO-008-2 IRO-017-1

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

IRO and TOP Reliability Standards Supersession Mapping

Standard TOP-005-2a — Operational Reliability Information	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
Requirement R1	IRO-010-2 TOP-003-3
Requirement R2	TOP-003-3
Requirement R3	Retired

Standard TOP-006-2 — Monitoring System Conditions	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
Requirement R1	IRO-010-2 TOP-001-4 TOP-003-3
Requirement R2	IRO-002-4 TOP-001-4
Requirement R3	IRO-010-2 TOP-003-3
Requirement R4	TOP-003-3
Requirement R5	IRO-002-5 TOP-001-4

IRO and TOP Reliability Standards Supersession Mapping

Standard TOP-006-2 — Monitoring System Conditions	
Requirement Being Superseded	Superseding BCUC Approved Standard(s)
Requirement R6	TOP-003-3
Requirement R7	IRO-002-5 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 R1	IRO-008-2 TOP-001-4
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)

IRO and TOP Reliability Standards Supersession Mapping

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 , 2019

Introduction:

This document is to be used in conjunction with the NERC Glossary dated July 3, 2018.

- 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, 2018 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 July 3, 2018 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
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

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

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
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.
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

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

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
CIP Exceptional Circumstance	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
CIP Senior Manager	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Composite Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Confirmed Interchange	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Composite Protection System	-	Report No. 9	R-32-16A	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
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.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Demand-Side Management	DSM	Report No. 9	R-32-16A	Adoption	October 1, 2016
Dial-up Connectivity	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Distribution Provider	DP	Report No. 10	R-39-17	Adoption	October 1, 2017
Disturbance	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Dynamic Interchange Schedule or Dynamic Schedule	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Electronic Access Control or Monitoring Systems	EACMS	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Electronic Access Point	EAP	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
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

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
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
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	Report No. 10	R-39-17	Adoption	To be determined ³
Interactive Remote Access	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interchange Authority	IA	Report No. 10	R-39-17	Adoption	October 1, 2017

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

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Interchange Meter Error (IME)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Interconnected Operations Service	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Interconnection Reliability Operating Limit	IROL	Report No. 6	R-41-13	Adoption	December 12, 2013
Intermediate Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Intermediate System	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Interpersonal Communication	-	Report No. 9	R-32-16A	Adoption	October 1, 2017
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
Low Impact BES Cyber System Electronic Access Point ⁴	LEAP	Report No. 10		Adoption	Not recommended for adoption in B.C at this time.
Low Impact External Routable Connectivity ⁴	LERC	Report No. 10		Adoption	Not recommended for adoption in B.C at this time.
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

⁴ Intended for CIP-003-6 and to be held in abeyance and be of no force or effect in B.C. due to technical suitability issues. When adopted by FERC, the NERC approved CIP-003-7(i) will retire the NERC Glossary terms. CIP-003-7(i) is anticipated to be assessed in the next MRS Assessment Report.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Native Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Non-Consequential Load Loss	-	TPL-001-4	R-27-18A	Adoption	July 1, 2019
Non-Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
Operating Instruction	-	Report No. 9	R-32-16A	Adoption	April 1, 2017
Operational Planning Analysis ²	-	Report No. 6	R-41-13	Adoption	December 12, 2013
Operational Planning Analysis ²	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Operational Planning Analysis ²	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Operational Planning Analysis	OPA	Report No. 12		Adoption	
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
Point of Receipt	POR	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
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		Adoption	
Protection System Maintenance Program	PSMP	Report No. 8	R-38-15	Adoption	Align with effective date of Requirement 1 of the PRC-005-2 standard where this term is referenced
Protection System Maintenance Program (PRC-005-4) ⁵	PSMP	Report No. 9		-	Not recommended for adoption in B.C at this time.
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
Reactive Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Real Power	-	Report No. 10	R-39-17	Adoption	October 1, 2017

⁵ Intended for reliability standard PRC-005-4 which was deferred by FERC and is not included in Assessment Report No. 9.

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Real-time Assessment ²	-	Report No. 6	R-41-13	Adoption	January 1, 2014
Real-time Assessment ²	-	Report No. 9	R-32-16A	Adoption	October 1, 2016
Real-time Assessment	RTA	Report No. 12		Adoption	
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
Remedial Action Scheme ²	RAS	Report No. 1	G-67-09	Adoption	June 4, 2009
Remedial Action Scheme	RAS	Report No. 9		-	To be determined ³
Removable Media ²	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Removable Media	-	Report No. 12		Adoption	
Reporting ACE	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Reportable Balancing Contingency Event ¹	-	Report No. 10	R-39-17	Adoption	January 1, 2018

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Reportable Cyber Security Incident	-	Report No. 8	R-38-15	Adoption	Align with effective date of CIP Version 5 standards (CIP-002-5.1, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1) where this term is referenced.
Request for Interchange	RFI	Report No. 8	R-38-15	Adoption	October 1, 2015
Reserve Sharing Group	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Reserve Sharing Group Reporting ACE ¹	-	Report No. 10	R-39-17	Adoption	January 1, 2018
Resource Planner	RP	Report No. 10	R-39-17	Adoption	October 1, 2017
Scheduled Net Interchange (NIs)	-	Report No. 11	R-33-18	Adoption	October 1, 2019
Sink Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Source Balancing Authority	-	Report No. 8	R-38-15	Adoption	October 1, 2015
Special Protection System (Remedial Action Scheme) ²	SPS	Report No. 1	G-67-09	Adoption	June 4, 2009
Special Protection System (Remedial Action Scheme)	SPS	Report No. 10	R-39-17	Adoption	Held in abeyance due to PC dependencies
Spinning Reserve	-	Report No. 11	R-33-18	Retirement	October 1, 2018
System Operating Limit	-	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

NERC Glossary Term	Acronym	Assessment Report Number	BCUC Order Number	BCUC Adoption or Retirement	Effective Date
Transient Cyber Asset ²	-	Report No. 10	R-39-17	Adoption	October 1, 2018
Transient Cyber Asset	TCA	Report No. 12		Adoption	
Transmission Customer	-	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Operator	TOP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Owner	TO	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Planner	TP	Report No. 10	R-39-17	Adoption	October 1, 2017
Transmission Service Provider	TSP	Report No. 10	R-39-17	Adoption	October 1, 2017
Under Voltage Load Shedding Program	-	Report No. 9		-	To be determined ³
Right-of-Way	ROW	Report No. 7	R-32-14	Adoption	August 1, 2015
TLR (Transmission Loading Relief) Log	-	Report No. 7	R-32-14	Adoption	August 1, 2014
Vegetation Inspection	-	Report No. 7	R-32-14	Adoption	August 1, 2015

Table 2 NERC Glossary Adoption History in 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	

NERC Glossary of Terms Version Date	Assessment Report Number	BCUC Order Adoption Date	BCUC Order Adopting	Effective Date
October 6, 2017	Report No. 11	October 1, 2018	R-33-18	
July 3, 2018	Report No.12			

British Columbia Utilities Commission (BCUC)

Implementation Plan

Reliability Standard CIP-003-7 - Cyber Security – Security Management Controls

Requested Approvals

- Reliability Standard CIP-003-7- Cyber Security – Security Management Controls
- Definition of Transient Cyber Asset (TCA)
- Definition of Removable Media

Requested Retirements

- Reliability Standard CIP-003-5 - Cyber Security – Security Management Controls
- Definition of Transient Cyber Asset (TCA)
- Definition of Removable Media

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Coordinator or Interchange Authority
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On July 24, 2015, the BCUC issued Order No. R-38-15 pursuant to Assessment Report No. 8, approving ten Critical Infrastructure Protection (CIP) Reliability Standards (CIP Version 5) and new or modified definitions to be incorporated into the Glossary of Terms Used in Mandatory Reliability Standards, inclusive of the CIP-003-5 Reliability Standard with an effective date of October 1, 2018. Requirement R2 of the CIP-003-5 Reliability Standard requires the documentation and implementation of one or more cyber security policies pertaining to Low Impact Bulk Electric System (BES) Cyber Systems addressing the topics of cyber security awareness, electronic access control, physical security control, and Cyber Security Incident Response.

The CIP-003-5 Reliability Standard, while adopted by the Federal Energy Regulatory Commission (FERC) Order No. 791 in the United States of America (U.S.) on November 22, 2013, never actually became effective in the U.S. by the scheduled effective date of April 1, 2016.

On January 21, 2016, FERC Order No. 822 adopted CIP-003-6 in the U.S. The Order became effective in the U.S. on March 31, 2016 per the U.S. Federal Register and enforced an effective date of July 1, 2016 for CIP-003-6 with phased-in compliance dates. CIP-003-6 superseded CIP-003-5 and modified CIP-003-5 Requirement R2 by moving it into CIP-003-6 Requirement R1, Part 1.2, and limited the requirement language to require only documentation of Low Impact BES Cyber System policies instead of also requiring implementation. However, CIP-003-6 introduced a new Requirement R2 to document and implement one or more prescriptive Low Impact BES Cyber System cyber security plans addressing the topics of cyber security awareness, electronic access controls, physical security controls, and Cyber Security Incident Response in accordance with prescriptive elements identified per Attachment 1. CIP-003-6 also introduced new Low Impact External Routable Connectivity (LERC) and Low Impact Electronic Access Point (LEAP) NERC Glossary Terms in association with the electronic access control cyber security policy and cyber security plan requirements. The phased-in compliance dates for CIP-003-6 were as follows:

- Requirement R1, Part 1.2 (effective in the U.S. April 1, 2017; approximately 12 calendar months from the effective date of the Order adopting CIP-003-6) requiring one or more policies for cyber security awareness, physical security controls, electronic access controls, and Cyber Security Incident Response for Low Impact BES Cyber Systems,
- Requirement R2 (effective in the U.S. April 1, 2017; approximately 12 calendar months from the effective date of the Order adopting CIP-003-6) requiring implementation of one or more cyber security plans for Low Impact BES Cyber Systems addressing Attachment 1 Sections 1 through 4 which contain prescriptive topics addressing cyber security awareness, physical security controls, electronic access controls, and Cyber Security Incident Response,
 - Implementation of one or more cyber security plans per Attachment 1, Sections 1 and 4 (effective in the U.S. April 1, 2017; approximately 12 calendar months from the effective date of the Order adopting CIP-003-6) addressing cyber security awareness and Cyber Security Incident Response respectively, and
 - Implementation of one or more cyber security plans per Attachment 1, Sections 2 and 3 (effective in the U.S. September 1, 2018; approximately 17 calendar months from the effective date of the Order adopting CIP-003-6) addressing physical security controls and electronic access controls respectively.

FERC Order No. 822 also directed NERC, among other things, to (1) “develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems”; and (2) modify the definition of LERC in the NERC Glossary.

To address these directives, NERC modified Reliability Standard CIP-003-6 to become CIP-003-7. In responding to the transient devices directive, NERC modified the definitions of Transient Cyber Asset (TCA) and Removable Media. The revised definitions ensure the applicability of security controls, provide clarity, and accommodate the use of the terms for all impact levels: high, medium and low. The revised definitions will allow entities to deploy one program to manage TCAs and Removable Media across multiple impact levels.

Further, as an alternative to modifying the LERC definition, NERC retired the terms “LERC” and “LEAP”, incorporating those concepts within the requirement language.

On July 26, 2017, the BCUC issued Order No. R-39-17 pursuant to Assessment Report No. 10, holding the CIP-003-6 Reliability Standard in abeyance due to the ongoing standard revisions underway by NERC.

On April 19, 2018, FERC Order No. 843 adopted CIP-003-7 in the U.S. which superseded CIP-003-6. The Order became effective in the U.S. on June 25, 2018 per the U.S. Federal Register. CIP-003-7 did not modify CIP-003-6 Requirement R1, Parts 1.2.1, 1.2.2, and 1.2.4 or Requirement R2, Attachment 1, Sections 1, 2, and 4. However, FERC Order No. 843 delayed the initial compliance dates for Requirement R2, Attachment 1, Sections 2 and 3 to align with the effective date of CIP-003-7 (January 1, 2020). FERC Order No. 843 therefore effectively gave U.S. Registered Entities:

- Nearly four years from the effective date of the Order adopting CIP-003-6 in the U.S. (March 31, 2016) which introduced the requirement to document and implement one or more cyber security plans for Low Impact BES Cyber System associated physical security controls and electronic access controls (per CIP-003-7 Requirement R2, Attachment 1, Sections 2 and 3).
- At least 18 calendar months from the effective date of the Order adopting CIP-003-7 in the U.S. to implement net new requirements to:
 - Document one or more cyber security policies for Low Impact BES Cyber System associated Transient Cyber Asset Media and Removable Media (per CIP-003-7 Requirement R1, Part 1.2.5), and Low Impact BES Cyber System associated CIP Exceptional Circumstances (per CIP-003-7 Requirement R1, Part 1.2.6), and
 - Document and implement one or more cyber security plans for Low Impact BES Cyber System associated Transient Cyber Assets and Removable Media (per CIP-003-7 Requirement R2, Attachment 1, Section 5).

On September 27, 2018, the BCUC issued Order No. R-33-18 pursuant to Assessment Report No. 11, ordering that CIP-003-5 Requirements R2.2 and R2.3 pertaining to the documentation and implementation of Low Impact BES Cyber System electronic access control and physical security control policies be held in abeyance pending CIP-003-7 assessment in B.C. for potential adoption.

Effective Dates

The effective dates for the proposed Reliability Standard and Glossary terms are provided below.

Reliability Standard CIP-003-7

The Reliability Standard CIP-003- 7 shall become effective on the first day of the first calendar quarter after the effective date of the BCUC’s order approving the standard with the following exceptions for initial compliance.

Compliance Date for CIP-003-7, Requirement R1, Parts 1.2.2 and 1.2.3, and Requirement R2 (in reference to Attachment 1, Sections 2 and 3)

Registered Entities shall not be required to comply until the later of October 1, 2023 or four years after the effective date of Reliability Standard CIP-003-7.

Compliance Date for CIP-003-7, Requirement R1, Parts 1.2.5 and 1.2.6, and Requirement R2 (in reference to Attachment 1, Sections 1, 4, and 5)

Registered Entities shall not be required to comply until the later of October 1, 2021 or two years after the effective date of Reliability Standard CIP-003-7.

Glossary Definitions of Transient Cyber Asset and Removable Media

The definitions of Transient Cyber Asset and Removable Media shall become effective coincident with the effective date of the CIP-003-7 Reliability Standard after BCUC adoption.

Planned or Unplanned Changes

Planned or Unplanned Changes Resulting in a Higher Categorization – This Implementation Plan incorporates by reference the section in the BCUC Implementation Plan for Version 5 CIP Cyber Security Standards included in BCUC Order No. R-38-15 titled Planned or Unplanned Changes Resulting in a Higher Categorization.¹

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

Retirement Date

Reliability Standard CIP-003-5

Reliability Standard CIP-003-5 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-7.

¹ Due to the length of that section, it is not reproduced herein.

British Columbia Utilities Commission (BCUC)

Implementation Plan

~~Project 2016-02 Modifications to CIP Standards –~~
Reliability Standard CIP-003-7 - Cyber Security –
Security Management Controls

Requested Approvals

- Reliability Standard CIP-003-7- Cyber Security – Security Management Controls
- Definition of Transient Cyber Asset (TCA)
- Definition of Removable Media

Requested Retirements

- Reliability Standard CIP-003-~~6~~5 - Cyber Security – Security Management Controls
- ~~• Definition Low Impact BES Cyber System Electronic Access Point (LEAP)~~
- ~~• Definition of Low Impact External Routable Connectivity (LERC)~~
- Definition of Transient Cyber Asset (TCA)
- Definition of Removable Media

Applicable Entities

- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Interchange Coordinator or Interchange Authority
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On ~~January~~ July 24, 2015~~21, 2016~~, the ~~Federal Energy Regulatory Commission (Commission)~~ BCUC issued Order No. ~~822R-38-15~~ pursuant to Assessment Report No. 8, approving ~~seven~~ ten Critical Infrastructure Protection (CIP) Reliability Standards (CIP Version 5) and new or modified definitions to be incorporated into the Glossary of Terms Used in ~~NERC Mandatory Reliability Standards (NERC Glossary)~~, inclusive of the CIP-003-5 Reliability Standard with an effective date of October 1, 2018. Requirement R2 of the CIP-003-5 Reliability Standard requires the documentation and implementation of one or more cyber security policies pertaining to Low Impact Bulk Electric System (BES) Cyber Systems addressing the topics of cyber security awareness, electronic access control, physical security control, and Cyber Security Incident Response.

The CIP-003-5 Reliability Standard, while adopted by the Federal Energy Regulatory Commission (FERC) Order No. 791 in the United States of America (U.S.) on November 22, 2013, never actually became effective in the U.S. by the scheduled effective date of April 1, 2016.

On January 21, 2016, FERC Order No. 822 adopted CIP-003-6 in the U.S. The Order became effective in the U.S. on March 31, 2016 per the U.S. Federal Register and enforced an effective date of July 1, 2016 for CIP-003-6 with phased-in compliance dates. CIP-003-6 superseded CIP-003-5 and modified CIP-003-5 Requirement R2 by moving it into CIP-003-6 Requirement R1, Part 1.2, and limited the requirement language to require only documentation of Low Impact BES Cyber System policies instead of also requiring implementation. However, CIP-003-6 introduced a new Requirement R2 to document and implement one or more prescriptive Low Impact BES Cyber System cyber security plans addressing the topics of cyber security awareness, electronic access controls, physical security controls, and Cyber Security Incident Response in accordance with prescriptive elements identified per Attachment 1. CIP-003-6 also introduced new Low Impact External Routable Connectivity (LERC) and Low Impact Electronic Access Point (LEAP) NERC Glossary Terms in association with the electronic access control cyber security policy and cyber security plan requirements. The phased-in compliance dates for CIP-003-6 were as follows:

- Requirement R1, Part 1.2 (effective in the U.S. April 1, 2017; approximately 12 calendar months from the effective date of the Order adopting CIP-003-6) requiring one or more policies for cyber security awareness, physical security controls, electronic access controls, and Cyber Security Incident Response for Low Impact BES Cyber Systems,
- Requirement R2 (effective in the U.S. April 1, 2017; approximately 12 calendar months from the effective date of the Order adopting CIP-003-6) requiring implementation of one or more cyber security plans for Low Impact BES Cyber Systems addressing Attachment 1 Sections 1 through 4 which contain prescriptive topics addressing cyber security awareness, physical security controls, electronic access controls, and Cyber Security Incident Response,
 - Implementation of one or more cyber security plans per Attachment 1, Sections 1 and 4 (effective in the U.S. April 1, 2017; approximately 12 calendar months from the effective date of the Order adopting CIP-003-6) addressing cyber security awareness and Cyber Security Incident Response respectively, and

- o Implementation of one or more cyber security plans per Attachment 1, Sections 2 and 3 (effective in the U.S. September 1, 2018; approximately 17 calendar months from the effective date of the Order adopting CIP-003-6) addressing physical security controls and electronic access controls respectively.

FERC Order No. 822 also directed NERC In addition to approving the seven CIP Reliability Standards, the Commission, among other things, to directed NERC to: (1) “develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems”; and (2) modify the definition of LERC in the NERC Glossary.

RELIABILITY | ACCOUNTABILITY

~~With respect to the transient devices directive, the Commission stated:~~

~~32. After consideration of the comments received on this issue, we conclude that the adoption of controls for transient devices used at Low Impact BES Cyber Systems, including Low Impact Control Centers, will provide an important enhancement to the security posture of the bulk electric system by reinforcing the defense in depth nature of the CIP Reliability Standards at all impact levels. Accordingly, we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission’s concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk based approach reflected in the CIP version 5 Standards.~~

~~For the LERC directive, the Commission stated:~~

~~73. Based on the comments received in response to the NOPR, the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP 003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term “direct” as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP 003-6.~~

To address these directives, NERC modified Reliability Standard CIP-003-6 to become CIP-003-7. In responding to the transient devices directive, NERC modified the definitions of TCA Transient Cyber Asset (TCA) and Removable Media. The revised definitions ensure the applicability of security controls, provide clarity, and accommodate the use of the terms for all impact levels: high, medium



and low. The revised definitions will allow entities to deploy one program to manage TCAs and Removable Media across multiple impact levels.

Further, as an alternative to modifying the LERC definition, ~~the standard drafting team~~ NERC retired the terms “LERC” and “LEAP”, incorporating those concepts within the requirement language. __

On July 26, 2017, the BCUC issued Order No. R-39-17 pursuant to Assessment Report No. 10, holding the CIP-003-6 Reliability Standard in abeyance due to the ongoing standard revisions underway by NERC.

On April 19, 2018, FERC Order No. 843 adopted CIP-003-7 in the U.S. which superseded CIP-003-6. The Order became effective in the U.S. on June 25, 2018 per the U.S. Federal Register. CIP-003-7 did not modify CIP-003-6 Requirement R1, Parts 1.2.1, 1.2.2, and 1.2.4 or Requirement R2, Attachment 1, Sections 1, 2, and 4. However, FERC Order No. 843 delayed the initial compliance dates for Requirement R2, Attachment 1, Sections 2 and 3 to align with the effective date of CIP-003-7 (January 1, 2020). FERC Order No. 843 therefore effectively gave U.S. Registered Entities:

- Nearly four years from the effective date of the Order adopting CIP-003-6 in the U.S. (March 31, 2016) which introduced the requirement to document and implement one or more cyber security plans for Low Impact BES Cyber System associated physical security controls and electronic access controls (per CIP-003-7 Requirement R2, Attachment 1, Sections 2 and 3).
- At least 18 calendar months from the effective date of the Order adopting CIP-003-7 in the U.S. to implement net new requirements to:
 - Document one or more cyber security policies for Low Impact BES Cyber System associated Transient Cyber Asset Media and Removable Media (per CIP-003-7 Requirement R1, Part 1.2.5), and Low Impact BES Cyber System associated CIP Exceptional Circumstances (per CIP-003-7 Requirement R1, Part 1.2.6), and
 - Document and implement one or more cyber security plans for Low Impact BES Cyber System associated Transient Cyber Assets and Removable Media (per CIP-003-7 Requirement R2, Attachment 1, Section 5).

On September 27, 2018, the BCUC issued Order No. R-33-18 pursuant to Assessment Report No. 11, ordering that CIP-003-5 Requirements R2.2 and R2.3 pertaining to the documentation and implementation of Low Impact BES Cyber System electronic access control and physical security control policies be held in abeyance pending CIP-003-7 assessment in B.C. for potential adoption.

Effective Dates

The effective dates for the proposed Reliability Standard and ~~NERC~~ Glossary terms are provided below.

Reliability Standard CIP-003-7

~~Where approval by an applicable governmental authority is required, The~~ Reliability Standard CIP-003- 7 shall become effective on the first day of the first calendar quarter ~~that is eighteen (18) calendar months after the effective date after of the effective date of the applicable governmental~~



~~authority's BCUC's order approving the standard with the following exceptions for initial compliance. , or as otherwise provided for by the applicable governmental authority.~~

~~Where approval by an applicable governmental authority is not required, Reliability Standard CIP-003-7 shall become effective on the first day of the first calendar quarter that is eighteen (18) calendar 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 CIP-003-7, Requirement R1, Parts 1.2.2 and 1.2.3, and Requirement R2 (in reference to Attachment 1, Sections 2 and 3)~~

~~Registered Entities shall not be required to comply until the later of October 1, 2023 or four years after the effective date of Reliability Standard CIP-003-7.~~

~~Compliance Date for CIP-003-7, Requirement R1, Parts 1.2.5 and 1.2.6, and Requirement R2 (in reference to Attachment 1, Sections 1, 4, and 5)~~

~~Registered Entities shall not be required to comply until the later of October 1, 2021 or two years after the effective date of Reliability Standard CIP-003-7.~~

NERC Glossary Definitions of Transient Cyber Asset and Removable Media

~~Where approval by an applicable governmental authority is required, t~~The definitions of Transient Cyber Asset and Removable Media shall become effective coincident with the effective date of the CIP-003-7 Reliability Standard after BCUC adoption. on the first day of the first calendar quarter that is eighteen (18) calendar months after the effective date of the applicable governmental authority's order approving the definitions, or as otherwise provided for by the applicable governmental authority.

~~Where approval by an applicable governmental authority is not required, the definitions of Transient Cyber Asset and Removable Media shall become effective on the first day of the first calendar quarter that is eighteen (18) calendar months after the date that the definitions are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.~~

Planned or Unplanned Changes

Planned or Unplanned Changes Resulting in a Higher Categorization – This Implementation Plan incorporates by reference the section in the BCUC Implementation Plan for Version 5 CIP Cyber Security Standards ~~BCUC Implementation Plan~~ included in BCUC Order ~~the BCUC order~~ No. -R-38-15 associated with CIP-003-5 titled Planned or Unplanned Changes Resulting in a Higher Categorization.¹

Unplanned Changes Resulting in Low Impact Categorization – ~~This Implementation Plan incorporates by reference the section in the Implementation Plan associated with CIP-003-6 titled Unplanned Changes Resulting in Low Impact Categorization. That section provides:~~

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

Retirement Date

Reliability Standard CIP-003-65

Reliability Standard CIP-003-65 shall be retired immediately prior to the effective date of Reliability Standard CIP-003-7 in the particular jurisdiction in which the revised standard is becoming effective.

Current NERC Glossary of Terms Definition(s) of LERC, LEAP, TCA and Removable Media

The current definitions of LERC and LEAP shall be retired from the NERC Glossary immediately prior to the effective date of Reliability Standard CIP-003-7 in the particular jurisdiction in which the revised standard is becoming effective.

The current definitions of Transient Cyber Asset and Removable Media shall be retired from the NERC Glossary immediately prior to the effective date of the revised definitions for those terms in the particular jurisdiction in which the revised definitions are becoming effective.

¹ Due to the length of that section, it is not reproduced herein.

British Columbia Utilities Commission (BCUC)

Implementation Plan

Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite Standard

- None

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Background

The Reliability Standard PRC-025-1 went into effect in British Columbia (B.C.) starting on October 1, 2017 under a phased implementation plan (40% of load-responsive relays compliant by October 1, 2017, 60% of load-responsive relays compliant by October 1, 2018, 80% of load-responsive relays compliant by October 1, 2019, and 100% of load-responsive relays compliant by October 1, 2020). The phased timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to:

- 1) Apply settings to its existing load- responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection, and/or
- 2) Replace legacy load-responsive protective relays with modern advanced-technology relays that can be set using functions such as load encroachment, and/or
- 3) Remove load-responsive protective relays as the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

This Implementation Plan supersedes and retires the phased implementation timeframe per PRC-025-1 such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. This Implementation Plan considers the scope of the PRC-025-2 revisions and the timing for BCUC approvals with respect to the phased-in implementation dates for PRC-025-1. The latest B.C. phased-in implementation date for PRC-025-1 of October 1, 2020 applies to both load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection and to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities,
- The proposed revisions to Options 14b, 15b, and 16b may give reason for entities to re-evaluate their settings for load-responsive protective relays,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

The standard shall become effective on the first day of the first calendar quarter after the effective date of the BCUC Order approving the standard.

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load- responsive protective relay while maintaining reliable fault protection.	The later of October 1, 2020 or 12 months after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below.

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	Application and Relay Type	Implementation Date
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V- R – voltage-restrained) ¹	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

¹ Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for 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 (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for 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 (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in BCUC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2.

Phased-In Retirement

None

British Columbia Utilities Commission (BCUC)

Implementation Plan

~~Project 2016-04 – Modifications to PRC-025-1~~
Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite Standard

- None

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

~~No definitions are proposed as a part of this standard.~~

Background

The Reliability Standard PRC-025-1 went into effect in ~~the United States~~ British Columbia (B.C.) on ~~starting on~~ October 1, 2014-2017 under a phased implementation plan (40% of load-responsive relays compliant by October 1, 2017, 60% of load-responsive relays compliant by October 1, 2018, 80% of load-responsive relays compliant by October 1, 2019, and 100% of load-responsive relays compliant by October 1, 2020) ~~based on two time frames.~~ The first phased timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to:-

- 1) ~~apply~~ Apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection, and/or
- 2) ~~The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to~~ Replace a legacy load-responsive protective relays with a modern advanced-technology relays that can be set using functions such as load encroachment, and/or
- 4)3) ~~that~~ Removal of the load-responsive protective relays is as the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

RELIABILITY | ACCOUNTABILITY

General Considerations

This Implementation Plan supersedes and retires the phased implementation timeframe per PRC-025-1 Implementation Plan PRC-025-1 – Generator Relay Loadability¹ such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. ~~In drafting this Implementation Plan, the PRC-025-2 standard drafting team considered~~ considers the scope of the ~~proposed PRC-025-2~~ revisions and the timing for ~~regulatory BCUC~~ approvals with respect to the phased-in implementation dates for PRC-025-1. The ~~first latest B.C.U.S.~~ phased-in implementation date for PRC-025-1 of October 1, ~~2019-2020~~ applies to both load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. ~~The second U.S. phased-in implementation date for PRC-025-1 of October 1, 2021 applies and~~ to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities,
- The proposed revisions to Options 14b, 15b, and 16b may give reason for entities to re-evaluate their settings for load-responsive protective relays,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

~~Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's 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 after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.~~

¹ [http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_\(Clean\).pdf](http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_(Clean).pdf)

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	~~Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the~~ <u>The later of October 1, 2019-2020 or 12 months</u> after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below. ~~Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the later of October 1, 2021 or 36 months after the effective date of Reliability Standard PRC-025-2, except as noted for the Table 1 Relay Loadability Evaluation Criteria Options listed below~~

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	Application and Relay Type	Implementation Date
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V- R – voltage-restrained) ²¹	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

²₁_____ Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for 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 (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for 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 (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in ~~NERC-BCUC~~ Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 ~~in B.C. in the particular jurisdiction in which the revised standard is becoming effective.~~

Phased-In Retirement

None

~~Implementation Plan for Definitions~~

~~No definitions are proposed as a part of this standard.~~