BC HYDRO MRS RELIABILITY COORDINATOR REGISTRATION EXHIBIT B-1

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October 29, 2018

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)**
**Reliability Coordinator (RC) Registration Filing (the Filing)**

BC Hydro writes to provide its Filing in support of its application to register for the RC function in British Columbia (**B.C.**). In accordance with the Registration Manual, Appendix 1 to Rules of Procedure for MRS in B.C., BC Hydro submitted its application for registration as RC for B.C. with the Western Electricity Coordinating Council on September 4, 2018.

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

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Enclosure (1)

Copy to: B.C. MRS Program Registered Entities

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# BC Hydro MRS Reliability Coordinator

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# Chapter 1

## Introduction

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## 1.1 Executive Summary

BC Hydro submitted its application for registration as Reliability Coordinator (**RC**) for British Columbia (**B.C.**) with the Western Electricity Coordinating Council (**WECC**) on September 4, 2018, provided for reference as Appendix A. BC Hydro is providing this filing in support of its application for the RC function. In July 2018 Peak Reliability (**PEAK**), the existing RC for B.C., announced that it will no longer provide RC services after December 31, 2019. An RC is required in order to preserve reliability of the electricity grid and for compliance with the Mandatory Reliability Standards (**MRS or Reliability Standards**). BC Hydro has examined RC options for B.C. and has concluded it is in the best position to assume this role. With BC Hydro as RC for the province of B.C. the reliability of the electricity grid will be strengthened with staff familiar with provincial operations, a strong governance framework, and more control over ongoing sustainment costs for RC services in the future. BC Hydro estimates its annual costs to provide RC services to be in the range of $2.5 million to $2.8 million; approximately $1.6 to $1.9 million less than the annual fee paid to PEAK for 2018.

## 1.2 Introduction

The electricity grid in B.C. is part of a large interconnected grid in western Canada, the western United States of America (**U.S.**) and northern Mexico known as the Western Interconnection. The planning and operation of interconnected grids is facilitated by compliance with the MRS which has evolved from best practices across North American utilities. Such standards are developed under the guidance of the North American Electric Reliability Corporation (**NERC**). In B.C., the British Columbia Utilities Commission (**BCUC or Commission**) under the authority of section 125.2 of the *Utility Commission Act* (**the Act**) determines the applicability of the MRS in B.C.

The RC function is responsible for assessing transmission reliability, coordinating system operations, and directing actions to preserve the integrity and reliability of the

Bulk Electric System (**BES**). Since 2013 PEAK has been responsible for reliability coordination services in the Western Interconnection except for Alberta. In October 2014, BC Hydro executed a five year membership agreement with PEAK. On December 19, 2014 the Commission issued Letter No. L-65-14 recognising PEAK as the RC for the B.C. Balancing Authority Area and directing registered entities to follow the directions of PEAK as the RC.

Recently PEAK has announced it will be winding down operations and will no longer provide RC services effective December 31, 2019. BC Hydro has examined RC options for B.C. and proposes to become the RC for B.C. Accordingly, on September 4, 2018, BC Hydro submitted its application for registration as the RC in B.C. with WECC, who acts as the Commission's MRS administrator. This filing provides information in support of BC Hydro's application for registration as RC.

### 1.2.1 Overview of Reliability Coordinator (RC) Function

The role of RC is one of the 11 function types that entities may register as under the Commission's Rules of Procedure for Reliability Standards (**Rules of Procedure**) in B.C. These function types are listed below in Table 1-1. BC Hydro is presently registered with the Commission for all functional types except that of RC.

**Table 1-1 Function Types in B.C.**

| Function Type | Acronym | BC Hydro Registration (Y/N) |
|---|---|---|
| Balancing Authority | BA | Y |
| Distribution Provider | DP | Y |
| Generator Operator | GOP | Y |
| Generator Owner | GO | Y |
| Planning Authority/Planning Coordinator | PA/PC | Y[1] |
| Reliability Coordinator | RC | N |
| Resource Planner | RP | Y |
| Transmission Owner | TO | Y |
| Transmission Operator | TOP | Y |
| Transmission Planner | TP | Y |
| Transmission Service Provider | TSP | Y |

The NERC Glossary of Terms adopted in B.C. defines the role of RC as:

> "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."

Since the adoption of MRS in B.C. in 2009, the role of RC in B.C. has been provided by either WECC or PEAK. BC Hydro, in its various functional roles has complied with the requirements of the Reliability Standards that describe how entities are to interact with their RC, including the sharing of operational and planning information and following the directions of the RC when necessary to ensure the reliable operation of the BES.

[1] The PC function is equated to the PA function through the NERC Glossary. BC Hydro is registered as a PA in B.C. and so therefore is acting as the PA/PC for the BC Hydro Asset Footprint only.

RCs use operational tools and information to analyze the reliability of the power system on a continuous basis. They have a wider view of the interconnected grid than any single Transmission Operator and have the responsibility to ensure that there is adequate coordination and oversight to reliably operate the interconnected grid in real time and on a day-ahead basis. In the event of disturbances or blackouts, RCs intervene to ensure that the restoration of the grid is done in a coordinated manner.

The RC function is staffed by persons who have been certified by NERC, meet annual training requirements, and have significant experience in operating or planning the BES.

## 1.3 Applicant

BC Hydro is a Crown Corporation established in 1962 under the *Hydro and Power Authority Act*. BC Hydro's mandate is to generate, distribute and sell electricity; upgrade its power sites; and purchase power from, or sell power to, a firm or person. BC Hydro is the largest electric utility in B.C., serving over 94 per cent of the provincial population.

### 1.3.1 Technical Capacity

BC Hydro safely and reliably operates a complex network of Generation, Transmission and Distribution systems across the province. As the BA for B.C., BC Hydro has visibility and coordinated control over the operation of facilities on the BES within the province. Real-time and day-ahead planning and operations are performed from two control centres which make use of advanced energy management tools that provide visibility, control, and study capabilities on a continuous basis.

BC Hydro has or will have the NERC-certified people, processes and tools to meet the requirements associated with the Reliability Standards applicable to the RC role for the B.C. Balancing Authority area footprint. Within BC Hydro, the real-time operation, and day-ahead planning of the electricity grid is performed within the Transmission & Distribution System Operations business unit.

#### *1.3.1.1 Transmission & Distribution System Operations (TDSO)*

TDSO is responsible for managing the real-time operation and day-ahead planning of the BC Hydro Generation, Transmission & Distribution systems. TDSO relies on input from other BC Hydro business units responsible for scheduling generation, maintenance, and the interconnection of new facilities. TDSO also coordinates with other registered entities in B.C. to ensure the reliable operation of non-BC Hydro facilities such as Independent Power Producers and B.C. entities with generation and/or transmission assets. TDSO also facilitates fair and open access to the transmission grid through administration of the Open Access Transmission Tariff (**OATT**) and operation of the wholesale transmission market. TDSO has staff located at control centres in the Fraser Valley and South Interior of B.C.

#### *1.3.1.2 Reliability Compliance*

BC Hydro has been regularly audited for compliance with applicable Reliability Standards including a number of Reliability Standards that also apply to RCs. BC Hydro's most recent MRS compliance audit was conducted by WECC on behalf of the BCUC in October 2017 covering a subset of Reliability Standards adopted in B.C. consisting of Operations and Planning Reliability Standards as well as Critical Infrastructure Protection (**CIP**) Reliability Standards.

BC Hydro's Regulatory department includes a separate Reliability Compliance team to provide oversight of those BC Hydro groups with responsibility for MRS compliance. The Reliability Compliance team is responsible for leading annual internal MRS compliance audits for the purposes of Self-Certification. The Reliability Compliance team also solicits feedback from BC Hydro groups on upcoming MRS developments in order to provide recommendations to NERC, WECC, and the BCUC, leads annual assessments of new/revised MRS adopted in the U.S., and educates BC Hydro groups on compliance audit approaches, reliability and compliance lessons learned.

### 1.3.2 Regulatory and Legal Context

The 2007 British Columbia Energy Plan stated that, because the B.C. transmission system is part of a much larger interconnected grid, B.C. will need to work with other jurisdictions to maximize the benefits of the interconnections, remain consistent with evolving North American Reliability Standards, and ensure B.C.'s infrastructure remains capable of meeting customer needs. To address these objectives the provincial government amended the Act on May 1, 2008 by adding section 125.2 giving the Commission jurisdiction to adopt MRS for application in B.C. and issued the MRS Regulation.

Commission Order No. G-123-09, dated October 15, 2009, adopted the Rules of Procedure, including the Registration Manual and the Compliance Monitoring Program setting out the administrative framework for the registration of functional entities and monitoring of compliance with MRS adopted in B.C. The Rules of Procedure were revised under Commission Order No. R-40-17, dated September 1, 2017, including revisions to the Registration Manual, Compliance Monitoring Program and Penalty Guidelines.

Commission Order No. G-123-09 also appointed WECC as the Commission's MRS Administrator and ordered that WECC will serve as RC for B.C. and that registered entities must follow the directions of the RC as required by Reliability Standards adopted in B.C.

Commission Letter No. L-65-14, dated December 19, 2014, acknowledged the bifurcation of WECC into WECC and PEAK and recognized PEAK as the RC for the B.C. Balancing Authority area.

### 1.3.3 RC Functional Registration by BC Hydro

BC Hydro submitted its application for registration as RC with WECC on September 4, 2018. The Registration Manual sets out the requirements for registration. BC Hydro notes that there is currently no formal administrative process to support registration as RC in B.C. Accordingly BC Hydro submits that the Commission may determine its own process and information necessary to determine whether an entity should be registered as an RC in B.C. BC Hydro has provided supplementary information to support its registration as RC in Chapter 4 of this filing.

Upon the Commission's acceptance of BC Hydro's registration as RC, it will be necessary for the Commission to rescind its recognition of PEAK as the RC for the B.C. Balancing Authority area and acknowledge BC Hydro as the registered RC for B.C.

### 1.3.4 Proposed Functional Registration Review Process

BC Hydro is providing this filing in support of BC Hydro's application for registration as the RC for B.C. Under the Registration Manual, the Commission may consider whether additional process or information is required and will then determine whether an entity should be registered for a particular function.

BC Hydro has completed an assessment of the RC options as set out in this filing and sought feedback from registered entities on its proposal to become the RC for B.C. For details on the stakeholder engagement process and summary of responses refer to Chapter 5.

Although it is ultimately up to the Commission to determine if any further processes, procedures or other documents, as indicated under the Registration Manual, are necessary to determine BC Hydro's functional registration as RC, BC Hydro respectfully recommends a process similar to that followed for the annual MRS assessment reports. In such a process, the Commission could:

- provide a workshop led by BC Hydro to explain the role of the RC and answer stakeholder questions, and
- engage WECC to conduct an assurance review.

Following this process, the Commission would then issue a determination on the acceptance of BC Hydro's application for registration as RC. BC Hydro has set out a schedule in section 4.3.2.1 that it believes is necessary to meet the timeline for it to become the RC in B.C.

## 1.4 Structure of the Filing

The Filing consists of six chapters.

| | |
|---|---|
| **Chapter 2** | Contains an overview of the Reliability Coordinator Function in B.C. |
| **Chapter 3** | Evaluation of the Reliability Coordinator function solutions |
| **Chapter 4** | Includes the Reliability Coordinator function solution description, cost and schedule information |
| **Chapter 5** | Details the stakeholder engagement activities conducted by BC Hydro |
| **Chapter 6** | Identifies risks and describes BC Hydro's risk management strategies |
| **Appendix A** | WECC Registration Request Form |
| **Appendix B** | List of Reliability Standards applicable to Reliability Coordinator Function |
| **Appendix C** | NERC Reliability Coordinator Standards of Conduct |

# BC Hydro MRS Reliability Coordinator Registration Filing

# Chapter 2

## Reliability Coordinator Function in B.C.

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## 2.1 Introduction

The functional role of RC has been in place in the Western Interconnection since the late 1990s. In the Western Interconnection, there were originally three reliability coordination entities established and funded by WECC to supervise grid reliability. The three RCs were:

- Pacific Northwest Security Coordinator (**PNSC**);
- Rocky Mountain Desert Southwest Reliability Coordinator (**RDRC**); and
- California-Mexico Reliability Coordinator (**CMRC**).

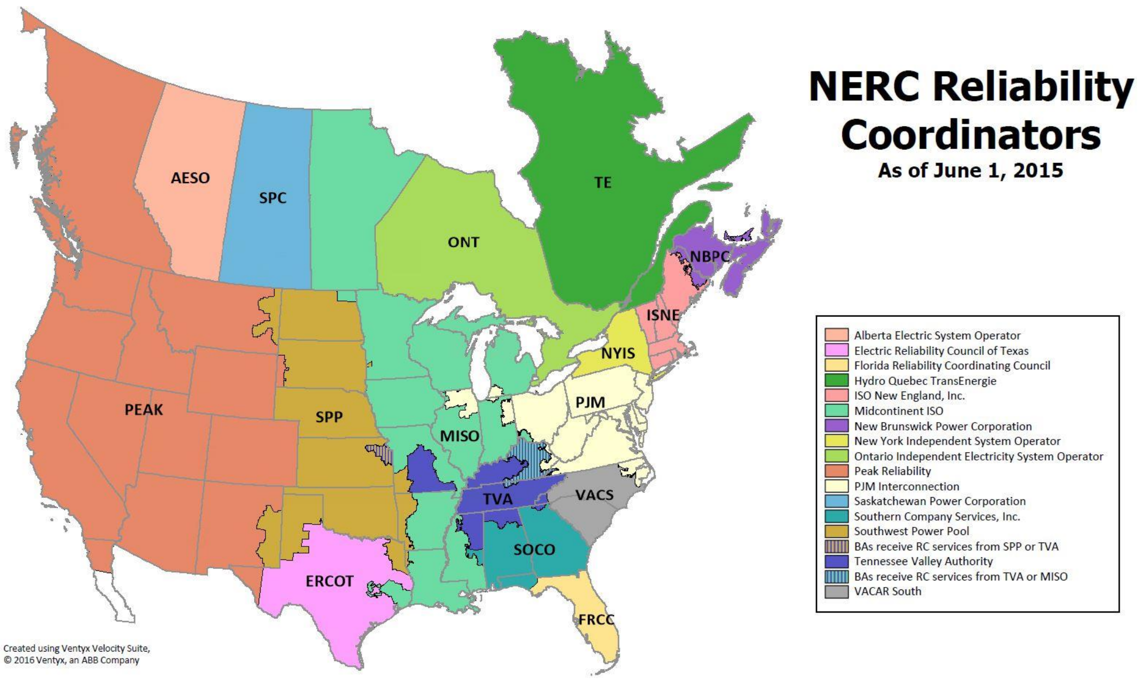
BC Hydro, as the BA for B.C., fell under the supervision of the PNSC which operated out of offices in Vancouver, Washington. In 2004 WECC began the process of consolidating the three RC entities into one to provide a single view of the entire Western Interconnection. By 2009 WECC had built two new reliability coordination centers, one in Vancouver, Washington and one in Loveland, Colorado and consolidated operations of the three RCs into one entity operating from both control centers.

Following the September 2011 blackout in the southwest of the U.S., WECC began efforts towards bifurcating into two entities; one responsible for RC services and one responsible for developing, monitoring and enforcing Reliability Standards, as well as promoting coordination amongst members. PEAK Reliability was founded on January 1, 2014 to provide RC services and BC Hydro executed a five-year membership agreement with PEAK effective October 2014.

The Alberta Electric System Operator (**AESO**) chose to self-provide their own RC services when Peak was setup, consequently there have been two RCs in the WECC footprint since the bifurcation.

Figure 2–1 below shows a map of the existing footprints of RCs in North America.

**Figure 2–1 RC Footprints in North America**




In early 2017 a group of ten electricity service providers,[2] mostly in Wyoming and Colorado, began discussions with the Southwest Power Pool (**SPP**) towards participation in a regional market and leveraging the RC services provided by the SPP. For these electricity service providers, participation in a regional energy market presented opportunities to reduce costs and increase reliability. Later in December 2017, PEAK announced that they had entered into a formal agreement with PJM Connext, a subsidiary of the Pennsylvania New Jersey Maryland Regional Transmission Organization, to develop an energy market in the Western Interconnection and leverage PJM Connext's tools and services. In January 2018 the California Independent System Operator (**CAISO**) announced that it would be withdrawing from PEAK and establishing RC services for itself and others.

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[2] https://www.spp.org/documents/54950/mountain%20west%20faqs%20through%20september%202017%20-%20updated%2010%2012%2017.pdf.

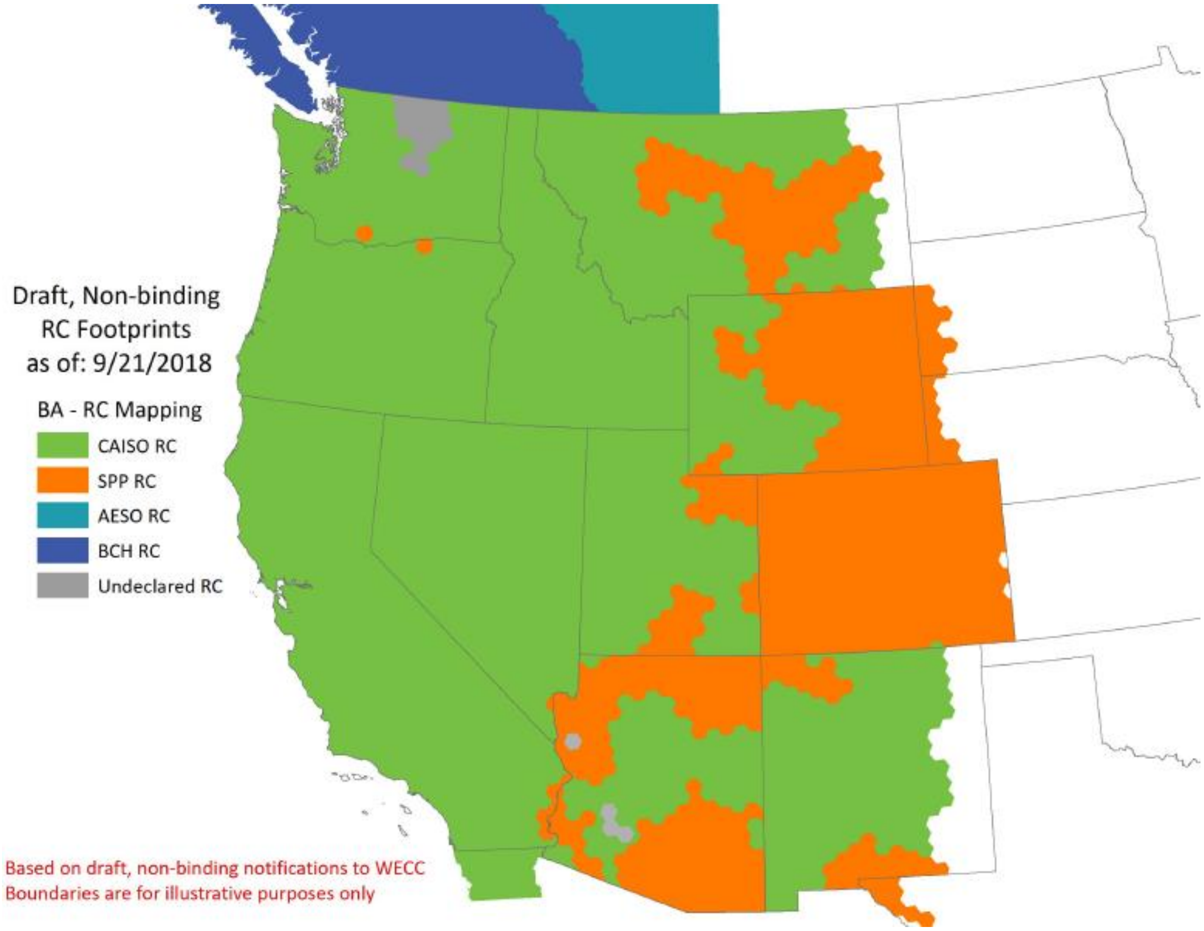
These developments led to erosion in the confidence of the members of PEAK and, after gathering feedback from members, PEAK announced on July 18, 2018 that it would be winding down and ceasing operations on December 31, 2019. PEAK also announced the termination of their collaboration with PJM Connext.

Since the announcement of the wind down of PEAK it has become clear that by the end of 2019 there will be new RC service providers in the Western Interconnection. Existing members of PEAK have either chosen, or are in the process of choosing to procure RC services from either SPP, CAISO, or providing their own RC services. On August 30, 2018 BC Hydro provided notice to PEAK of its intent to terminate its membership agreement effective September 2, 2019. Subsequently, on September 4, 2018, BC Hydro submitted an application to the BCUC, via WECC's website, to register to become the RC for the province of B.C. (Appendix A).

At the time of this filing, the latest indication of how the RC landscape is developing had been published by WECC in September 2018.[3] BAs representing approximately 72 per cent of the demand in the Western Interconnection have selected CAISO and 12 per cent have selected SPP as their RC provider. Alberta is already an RC representing about 7 per cent of demand and WECC was aware that BC Hydro, representing about 7 per cent of demand, had applied to register as an RC. Figure 2–2 is a map representing tentative selections collected by WECC.

3 https://www.wecc.biz/Reliability/180914_TentativeRC_Commitments.pdf.

**Figure 2–2 RC Tentative Commitments as of September 2018**




## 2.2 RC Membership and Services Fees

PEAK's membership and services fees are allocated to members based on their energy demand as a percentage of total demand in the Western Interconnection multiplied by PEAK's approved budget. B.C.'s energy demand is approximately 7 per cent of the total demand in the Western Interconnection and Peak's approved budget for 2015 was $42 million (USD) which led to BC Hydro's 2015 fees being assessed at $3.06 million (USD). By calendar year 2018 BC Hydro's membership fees had increased to $3.47 million (USD). PEAK's budget for 2019 has increased by 26 per cent to account for wind down costs which include incentives for staff to remain until the end of 2019. BC Hydro, as the BA for B.C., currently pays the PEAK fees for RC services in the province. As shown in Table 4-3 of this filing, BC Hydro estimates its annual costs to provide RC services to be between $2.51 million and $2.76 million. This is approximately $1.61 million to $1.86 million (CAN)[4] less than the annual fee paid to PEAK for 2018.

## 2.3 The RC Function in B.C.

The Rules of Procedure, Registration Manual, and Compliance Monitoring Program for MRS in B.C. were initially approved under BCUC Order No. G-123-09 issued on October 15, 2009. Directive 5 of this order established WECC as the RC and required that:

> "Entities registered as functional entities must follow the directions of the Reliability Coordinator, as required by adopted British Columbia reliability standards, unless otherwise ordered by the Commission."

Following the bifurcation of WECC and the establishment of PEAK, BCUC Letter No. L-65-14 issued on December 19, 2014 recognized PEAK as the RC for the B.C. Balancing Authority area.

With PEAK's announcement that it will cease operations at the end of 2019, in order to maintain compliance with the MRS, and maintain the same level of grid reliability that exists today, an RC will need to be recognized or registered in B.C. to replace PEAK.

### 2.3.1 RC Role and Activities

The role of the RC is defined by the NERC Glossary of Terms adopted in B.C. (refer to section 1.1 of this filing). The activities that an RC undertakes in order to fulfill this role are driven by the requirements of the various Reliability Standards that are applicable to the RC function. Most of these requirements are found in the Interconnection Reliability Operations and Coordination (**IRO**) Reliability Standards,

[4] Based on BC Hydro Treasury forecast exchange rate of $1.26 USD/CAD.

some are in Reliability Standards that apply to RCs and other functional entities, and others can be found under Reliability Standards that require other functional entities to interact with the RC. The following section provides a summary of the activities performed by an RC.

### 2.3.2 RC Reliability Standards and Tasks

Appendix B contains a list of the Reliability Standards adopted in B.C. which directly or indirectly involve the role of RC and will be in effect as of September 2, 2019. The NERC Reliability Functional Model, Version 5 dated November 2009 (**NERC Functional Model**), describes the tasks associated with the role of the RC based on Reliability Standards in effect in the U.S. in 2009. While Reliability Standards have evolved and new Reliability Standards have been developed since then, and the NERC Functional Model is monitored to promote consistency, but not determinative in B.C., this task list provides an overview of activities associated with the RC role:

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and generation/transmission maintenance plans.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (**IROL**) to protect from instability and cascading.
4. Assist in determining reliability-related services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves).
5. Perform reliability analysis (actual and contingency) for the reliability area.
6. Direct revisions to transmission maintenance plans as permitted by agreements.
7. Direct revisions to generation maintenance plans as permitted by agreements.

8. Direct implementation of emergency procedures including load shedding.
9. Direct and coordinate system restoration.
10. Curtail Confirmed Interchange that adversely impacts reliability.

In addition, the RC has tasks associated with other RCs, TOPs, GOPs, and BAs. These tasks were also summarized in the NERC Functional Model on an ahead of time and a real time basis.

***Ahead of Time Tasks***

1. Coordinates with other RCs, TPs, and TSPs on transmission system limitations.
2. Receives facility and operational data from GOPs, Load-Serving Entities, TOs, GOs, and TOPs.
3. Receives generation dispatch from BAs and issues dispatch adjustments to BAs to prevent exceeding limits within the RC Area (if not resolved through market mechanisms).
4. Receives integrated operational plans from BAs for reliability analysis of RC Area.
5. Receives transmission and generation maintenance plans from TOs and GOs, respectively, for reliability analysis.
6. Develops Interconnection Reliability Operating Limits, based on TO’s and GO’s specified equipment ratings, and provides them to TOPs.
7. Assists TOPs in calculating and coordinating System Operating Limits.
8. Provides reliability analyses to TOPs, GOPs and BAs in its area as well as other RCs.
9. Directs GOs and TOs to revise generation and transmission maintenance plans that are adverse to reliability.
10. Receives balancing information from BAs for monitoring.

11. Receives final approval or denial of Arranged Interchange from Interchange Coordinator.

12. Provide IROLs and Total Transfer Capability (**TTC**) to the TSP for Available Transfer Capability (**ATC**) calculations.

13. Develops operating agreements or procedures with TOs.

14. Coordinates with TOPs on system restoration plans, contingency plans and reliability-related services.

***Real Time Tasks***

1. Coordinates reliability processes and actions with and among other RCs.

2. Receives Real-time operational information from BAs, Interchange Coordinators and TOPs for monitoring.

3. Issues reliability alerts to GOPs, TOPs, TSPs, BAs, Interchange Coordinators, Regional Entities and NERC.

4. Issues corrective actions and emergency procedures directives (e.g., curtailments or load shedding) to TOPs, BAs, GOPs, DPs, and Interchange Coordinators.

5. Specifies reliability–related requirements (e.g., reactive requirements, location of operating reserves) to BAs.

6. Receives verification of emergency procedures from BAs.

7. Receives notification of Confirmed Interchange changes from BAs.

8. Orders re-dispatch of generation by BAs.

9. Directs use of flow control devices by TOPs.

10. Responds to requests from TOPs to assist in mitigating equipment overloads.

The BCUC’s approved Reliability Standards are the basis of BC Hydro’s assessment of RC options for B.C. as presented in Chapter 3.

# BC Hydro MRS Reliability Coordinator Registration Filing

# Chapter 3

## Reliability Coordinator Function Alternatives

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## 3.1 Introduction

With the recent activities of SPP to expand its footprint in the West, the work of CAISO to establish RC services for itself and others (refer to Figure 2-2), and PEAK winding down by the end of 2019 the following alternatives were identified as possible solutions and assessed:

| | |
|---|---|
| Alternative 1 | BC Hydro registers as the entity responsible for the RC function in B.C. |
| Alternative 2 | CAISO serves as RC function in B.C. |
| Alternative 3 | SPP serves as RC function in B.C. |
| Alternative 4 | AESO serves as RC function in B.C. |

As described in this chapter, Alternative 1 is the preferred alternative for providing RC services for B.C., and BC Hydro is moving forward to become registered as the RC for the B.C. Balancing Authority area.

## 3.2 RC Alternatives

The four alternatives that were considered by BC Hydro for provision of RC service in B.C. are discussed below.

### 3.2.1 Alternative 1 - BC Hydro as RC for B.C.

In taking on the role of RC for B.C., BC Hydro would be performing the role for the province. BC Hydro would have to meet a fixed implementation timeline to put in place the people, processes, and tools that would ensure compliance with the Reliability Standards associated with the RC role. Agreements related to responsibilities and data sharing would need to be established with other registered entities within B.C. and with neighbouring RCs. As the BA for B.C. and the TOP of the provincial Interties and 500 kV transmission system, BC Hydro already has the experience and most of the tools required to perform the role of RC for B.C.

BC Hydro as RC for the province will provide a strong governance framework, and control over sustainment costs for RC services in the future. Self-providing RC services within B.C. would be consistent with most other Canadian provinces as shown in Figure 2-1.

### 3.2.2 Alternative 2 - CAISO as RC for B.C.

In January 2018 CAISO announced they would be offering RC services to other utilities and verbally indicated the costs would be approximately one half of PEAK RC services. A CAISO whitepaper[5] published in April 2018 stated that their annual funding requirement for a fully staffed RC office was between $5 and $12 million (USD) depending on the size of the RC footprint. By June 2018 CAISO had increased their cost estimate to between $5 and $19 million (USD) with an estimate that customers would be charged between $0.02-0.06 (USD) per MWh of load.[6] CAISO filed their proposed rate design to the U.S. Federal Energy Regulatory Commission (**FERC**) in August 2018[7] and the range of costs in this filing is consistent with the June 2018 estimate. Most of the utilities that operate the grid between California and B.C. have indicated they will be seeking RC services from CAISO, so an extension of those services into B.C. is feasible. BC Hydro shares data and modeling information (a subset of requested RC information) with the CAISO as part of other initiatives. BC Hydro considers this alternative as the most practical alternative of the three external provider alternatives considered (Alternatives 2 through 4) for the reasons set out below.

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[5] http://www.caiso.com/Documents/StrawProposal-ReliabilityCoordinatorRateDesign-Terms-Conditions.pdf.

[6] http://www.caiso.com/Documents/DraftFinalProposal-ReliabilityCoordinatorRateDesign-Terms-Conditions.pdf.

[7] http://www.caiso.com/Documents/Aug31_2018_TariffAmendment-ReliabilityCoordinatorServicesRateDesign_Terms_Conditions_ER18-2366.pdf.

### 3.2.3 Alternative 3 - SPP Serves as RC for B.C.

SPP is one of ten U.S. RCs in the Eastern Interconnection and has been certified as an RC for over 20 years. However, as shown in Figure 2-2, there is a geographic separation between the expected SPP footprint and B.C, with CAISO in between. If SPP were to operate as RC in B.C., this could result in inefficiencies affecting outage coordination, day-to-day real-time operations, as well as emergency response. Three external RC providers (SPP, AESO and CAISO) would need to collaborate to provide oversight and direction of B.C.'s grid and its interties with the U.S. and Alberta.

Coordination of B.C.'s intertie with the U.S. would take place between SPP and CAISO with directions then given to operating staff in BC Hydro and Bonneville Power Administration (**BPA**). Coordination of B.C.'s intertie with Alberta would take place between SPP and AESO with direction then provided to operating staff in BC Hydro and the corresponding TOP in Alberta, Altalink. From a B.C. perspective, the involvement of an external RC such as SPP that has little experience operating in the Western Interconnection and no responsibilities for the grids directly adjacent to B.C. is more complex than an RC under Alternative 2 where CAISO would at least have responsibilities for the grid on both sides of the B.C.-USA border. For this reason, BC Hydro considers this Alternative to be less practical than Alternative 2 and did not pursue this Alternative further.

### 3.2.4 Alternative 4 - AESO as RC for B.C.

Although AESO has not offered RC services to BC Hydro or any other members of PEAK, BC Hydro has discussed the feasibility of this alternative with them. The AESO operates under a slightly different reliability framework than B.C. and modifies and adopts NERC Reliability Standards as necessary to protect reliability in Alberta. Therefore, RC related Reliability Standards in Alberta may have differences compared to the Reliability Standards in effect in B.C. Reconciling these differences would require additional time and effort involving operational and regulatory considerations in both provinces. The AESO is presently focused on establishing their capacity market structure. The timeline to have RC services in place before BC Hydro leaves PEAK in 2019 precludes expanding RC capabilities within AESO to cover B.C. As such, this alternative was not considered a practical option.

## 3.3 Evaluation and Comparison of Alternatives

As indicated above, BC Hydro concluded that Alternatives 3 and 4 were dismissed from a further comparison of alternatives. The evaluation and comparison of Alternatives 1 and 2 have been performed on reliability benefits, governance, implementation risk, and cost. The results are summarized in Table 3-1 below and in the subsequent sections in this chapter. For considerations other than cost, the alternatives were given a High, Medium or Low ranking for benefit or risk:

**Table 3-1 Evaluation of Alternatives 1 and 2**

| Alternative | Reliability Benefit | Governance Risk | Implementation Risk | Start-up Cost ($million CAN) | Annual Cost ($million CAN) |
|---|---|---|---|---|---|
| BC Hydro | High | Low | Medium | 1.77[8] – 2.30 | 2.51[8] – 2.76 |
| CAISO | Medium | Medium | Low | 0.25 – 0.50 | 1.60 – 4.70 |

### 3.3.1 Reliability Benefit Evaluation

There are two components to the reliability benefit evaluation of Alternatives 1 and 2. The first component is related to the reliability issues that arise within B.C. and/or its adjacent BAs. The second relates to WECC-wide reliability issues. This section evaluates each alternative against these components.

1. Reliability Issues arising in B.C. and/or in Adjacent BAs

**Alternative 1:** A B.C. RC will employ staff who are technical experts on the B.C. grid and very familiar with the coordinated operations of the interconnections with the adjacent BAs, Alberta and BPA. They would be using

[8] This number reflects the total costs before contingency.

sophisticated tools that are already customized to the B.C. and surrounding BAs. As such, they will be aware of operating risks and mitigation strategies that apply to the B.C. grid and would provide a high level of immediate knowledge and assurance to B.C. and adjacent BAs, so that compliance with Reliability Standards will be achieved.

**Alternative 2:** A CAISO RC, as with any large footprint external RC, would rely primarily on technical aids to identify unsafe operating conditions arising in or around the B.C. grid and this would likely provide coverage for most scenarios. However, for protecting the B.C. grid, technical tools implemented by CAISO will not be as effective if the RCs do not have significant familiarity with the B.C. grid. Furthermore, based on BC Hydro's experience working with PEAK since 2014, it is anticipated that the new CAISO RC would continually rely on BC Hydro expertise to fully understand and evaluate system conditions that their tools have identified as requiring attention.

2. WECC-Wide Reliability Issues

**Alternative 1:** A B.C. RC will actively coordinate with the CAISO, SPP and AESO RCs in the Western Interconnection to ensure that B.C. can withstand or respond to disturbances that occur outside B.C.; this combined with the B.C. RC actively evaluating the impact of major contingencies in the Western Interconnection will ensure reliability by identifying and mitigating WECC-wide reliability issues.

**Alternative 2:** With CAISO being the RC for B.C. as well as much of the Western Interconnection it is anticipated that there would be synergies in having multiple BAs and TOPs under the oversight of the CAISO RC for WECC-wide reliability issues. While there may be a benefit to having such coordination take place centrally instead of with an RC located in B.C., this benefit would likely be offset with the continued need to coordinate between the

CAISO RC staff responsible for B.C. and the BC Hydro staff who are more familiar with the B.C. grid.

**Reliability Benefit Evaluation Summary**: This evaluation highlights the higher reliability benefit associated with having BC Hydro as the RC for B.C. primarily through experienced staff working with tools customized to the B.C. grid, coordinating with other RCs, and evaluating and responding to reliability issues affecting B.C. and the Western Interconnection. Accordingly, BC Hydro attributes a high reliability benefit to Alternative 1 and a medium reliability benefit to Alternative 2.

### 3.3.2 Governance Risk Evaluation

This evaluation has been completed with consideration as to how an RC would structure its organization and establish governance protocols to manage the involvement and interests of its members and the province.

**Alternative 1**: To ensure independence BC Hydro staff will provide the RC services for B.C. in a similar way that other BC Hydro staff currently manage the BA function for the province and other MRS functions including the TSP for BC Hydro. BC Hydro staff will continue to operate under its current model which allows for transparent and open access of its transmission system through the BCUC approved OATT as well as the existing BC Hydro Standards of Conduct, which prevent non-public transmission information from being released to market function employees before it is publicly available. In taking on the function of the RC, BC Hydro will continue to make reliability and operational decisions independent of market influences and BC Hydro organizational structure. In addition, BC Hydro proposes that as part of the process of it being designated and approved by the BCUC as an RC functional entity in B.C. that BC Hydro will adhere to a RC Standards of Conduct in a form adopted by the BCUC. A copy of the NERC RC Standards of Conduct are included as Appendix C. The Standards of Conduct is discussed further in Chapter 4.

BC Hydro staff performing the RC function will be organized under a separate department with new compliance responsibilities distinct from the BA, TOP and other operational functions associated with managing the direct real-time and day-ahead operation of the BC Hydro grid. It is important to emphasize that BC Hydro's T&D System Operations staff and the B.C. RC Staff will be separate from all market function roles including market function employees of BC Hydro's subsidiary, Powerex Corp. which has its own board of directors.

BC Hydro as the RC for B.C. will address any issues and concerns raised by B.C. registered entities in a fair and non-discriminatory way, to ensure a positive outcome for the overall reliability of the province and the Western Interconnection. Furthermore, under Alternative 1 BC Hydro's compliance with the RC Reliability Standards will be under the jurisdiction of the BCUC.

**Alternative 2**: BC Hydro has reviewed public documents regarding CAISO's various roles and proposed governance structure. In addition to acting as a BA, TOP and TSP, CAISO also operates Day-ahead, Real-time and Ancillary Services markets for the state of California as well an Energy Imbalance Market that currently serves participants in eight states and the province of B.C. CAISO's RC footprint will cover entities located in ten U.S. states and one Mexican entity with an estimated total load that is over ten times larger than B.C.'s total load. CAISO has proposed to its RC members a governance structure that would have the RC function report to the VP of Operations at the CAISO. CAISO has stated there will be separation of the market operations and the reliability operations, however at this time it is not clear how the RC operations will be separated from market functions, and how decisions that are made from an operations perspective will be transparent and independent of market influence. It is proposed that entities that plan to join CAISO's RC would have membership in an Oversight Committee that would provide input and guidance to CAISO on the operations and performance of the RC. However, the CAISO board of directors would ultimately have final say regarding decisions involving the CAISO RC and at this time, only the state of California is able to appoint members to

CAISO's board of directors. Given the number of stakeholders and the proposed governance model, there is concern that B.C.'s interests may not be well protected with Alternative 2 and that other issues could emerge during the formation and early operation stages that have broader implications.

**Governance Risk Evaluation Summary**: Based on the above analysis and the uncertainty around CAISO's governance structure, BC Hydro considers the governance risk for B.C. of Alternative 1 to be low and the governance risk for B.C. of Alternative 2 to be medium.

### 3.3.3 Implementation Risk Evaluation

In evaluating the risks associated with the implementation of RC services, consideration was given to actions required by BC Hydro to support each alternative. These actions include the necessary people, process and technology changes that would support provision of RC services by the required dates.

**Alternative 1**: This alternative would require BC Hydro to implement people, process and technology changes within a tight timeline. Registration, evaluation of RC capabilities, consultation and the development of agreements with neighbouring RCs and registered entities within B.C. are all necessary activities. While there is effort required to implement this alternative, BC Hydro will have more control to decide what actions are required and how to complete them. For further discussion of these activities, please refer to Chapters 4 and 6.

**Alternative 2**: This alternative would require fewer changes within BC Hydro to implement due to BC Hydro having experience operating under an external RC provider. Furthermore, recent experience with other joint initiatives would indicate that BC Hydro and CAISO are able to coordinate well. The main implementation risk is that CAISO has an aggressive schedule to implement RC services for its own territory, become certified as an RC, and onboard more than 20 entities that have indicated they will be joining CAISO; all of which needs to be completed by fall 2019.

**Implementation Risk Evaluation Summary**: Based on the above analysis BC Hydro attributes a medium implementation risk to Alternative 1. BC Hydro has assessed a low implementation risk to Alternative 2 however this risk level may increase as CAISO further progresses along its implementation plans and schedule.

### 3.3.4 Financial Evaluation

To complete the financial evaluation, BC Hydro has considered the most current information available for both alternatives. BC Hydro has established a detailed cost estimate for Alternative 1 and has included contingency in the cost range. For Alternative 2, this analysis has been based on what is publicly available from CAISO and BC Hydro's experience with other initiatives.

**Alternative 1**: For BC Hydro to provide RC services under Alternative 1 it needs to recruit and train staff, build processes, enhance tools, and implement agreements with other entities to ensure compliance with the RC Reliability Standards. BC Hydro forecasts a one-time start-up cost of $1.77 – $2.30 million (including contingency) with ongoing annual expenses of $2.51 - $2.76 million to sustain RC operations. Start-up costs primarily cover project-related staffing, legal resources, software enhancements, building and equipment costs. Ongoing costs are primarily related to salaries. A breakdown of start-up and ongoing costs for Alternative 1 is provided in Chapter 4 of this filing.

**Alternative 2**: BC Hydro's cost estimate for Alternative 2, in which the CAISO provides RC services for B.C., is based on public information provided by the CAISO. The CAISO estimates the cost of RC services to be $0.02 – $0.06 (USD) per MWh of load served in the footprint to be covered. BC Hydro's membership dues with PEAK are based on a provincial load served of 62,325,587 MWh. Based on a forecast exchange rate of $1.26 USD/CAD for 2019[9] this would translate into an annual fee of $1.6 – $4.7 million (CAD). BC Hydro's start-up costs under Alternative 2 are difficult to estimate but would be less than Alternative 1 as there

[9] BC Hydro Treasury rates for fiscal 2020.

would be fewer costs associated with the implementation efforts. Without entering into formal information sharing agreements with CAISO, BC Hydro has assumed that start-up costs for Alternative 2 would be between $0.25 - $0.50 million (CAN). Ongoing costs for an external RC of the scale of CAISO are subject to fluctuation based on a number of uncertainties. Changes in the revenue requirements of CAISO, and potential cost escalations, could result from factors such as RC footprint changes (i.e., increase or decrease to paying members), response to the needs of the membership (e.g., additional tools and/or services) as well as indirect costs for compliance penalties and/or mitigations. These costs are billed in USD and remain uncertain due to currency fluctuations.

**Financial Evaluation Summary**: Based on the above evaluation, even though the financial costs associated with BC Hydro becoming the RC are higher for start-up and within the range of CAISO costs for sustainment, BC Hydro believes the cost control is better defined under Alternative 1. An added benefit is that the expenditures to provide RC services in B.C. are to a large extent incurred provincially.

### 3.3.5 Conclusion

In light of PEAK RC’s scheduled wind-up, four alternatives to provide RC services for B.C. were considered. Of the four alternatives the two strongest candidates were assessed: Alternative 1 – BC Hydro providing RC services and Alternative 2 – CAISO providing RC services.

When considering the overall reliability benefit, lower governance risk and costs of Alternative 1 with the lower implementation risks and similar costs associated with Alternative 2, it was determined that BC Hydro providing RC services for B.C. (Alternative 1) was the preferred alternative.

BC Hydro MRS Reliability Coordinator

Registration Filing

# Chapter 4

## Reliability Coordinator Function Solution

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## 4.1 Introduction

Based on the analysis presented in Chapter 3, BC Hydro has applied to register as the RC for B.C. For BC Hydro to perform the RC function in B.C., there are people, process, and technology enhancements required in order to ensure the continued reliability of the interconnected grid as well as maintaining compliance with the MRS. This chapter discusses these requirements, their costing and timeframe for implementation.

## 4.2 Components and Infrastructure

### 4.2.1 Staffing and Training

BC Hydro operational staff, located in the control centers in the Fraser Valley and South Interior, perform several operational roles including those of TOP, GOP, and BA. The TOP and GOP roles are related to the operation of BC Hydro's assets. The BA role is a provincial role that ensures that demand, generation and interchange are balanced within B.C. and that interconnection frequency is supported. All of these roles require around-the-clock staffing, and some roles have multiple staff working at the same time depending on the volume of work.

The role of RC will also need to be staffed on a continuous basis[10] and will be supported by technical staff that perform studies, develop and enhance tools, and support compliance activities. Ongoing training to stay abreast of Reliability Standards and tools and to obtain and maintain NERC certification credentials will be required.[11] RC staff will need to operate in facilities that meet the physical and cyber security requirements of the approved CIP Reliability Standards and so therefore will be located at BC Hydro's existing control centres.

The proposed departmental structure for this RC group is provided below in Figure 4–1 and the expected personnel roles are described in Table 4–1.

[10] As indicated in the PER-004-2 Reliability Standard.
[11] As indicated in the PER-003-1 Reliability Standard.

1 **Figure 4–1 RC Department Structure**

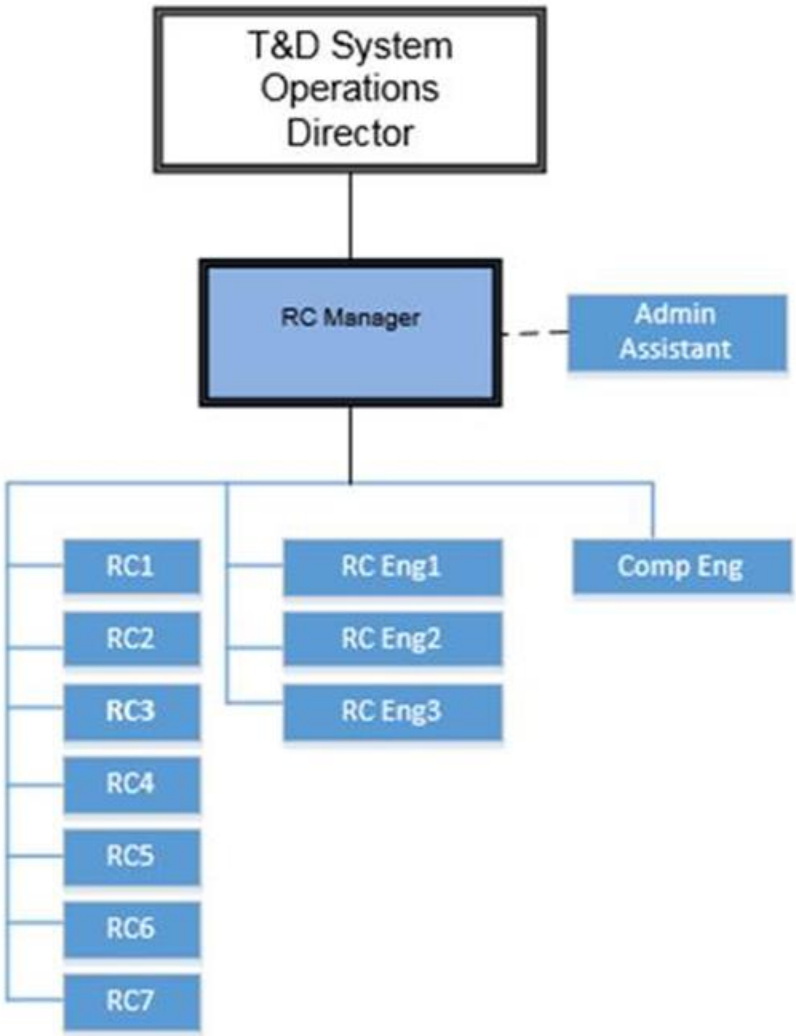


**Table 4–1 RC Roles**

| Reliability Coordination Role | Description of Role |
|---|---|
| RC Manager | Managerial oversight over staff, policies, compliance, and external relationships |
| RCs (seven positions) | Reliability Coordination for BC as part of a team of seven providing continuous real-time coverage on a rotating shift basis |
| RC Engineers (three positions) | Responsible for day-ahead studies, preparation of daily operation plans, coordinating exchange of information with external parties, and developing and enhancing tools |
| Compliance Engineer | Responsible for disturbance analysis, evidence gathering and documentation to support compliance activities |
| Administrative Assistant | Provides administrative support to RC team |

### 4.2.2 Agreements

Each RC is required to coordinate with other RCs in the interconnection.[12] Agreements are an effective means to clarify issues and expectations and ensure coordination and compliance with the Reliability Standards. BC Hydro expects to have agreements in place with PEAK, CAISO, SPP and AESO prior to beginning RC operations. Typical RC to RC agreements include specification of:

- Roles and Responsibilities of parties
- Data Exchange requirements
- Services Provided
- Congestion Management and Outage Scheduling procedures
- Coordination under emergency conditions
- Voltage Coordination procedures

RCs are also required to coordinate with registered entities within their RC footprint. BC Hydro intends to leverage existing processes and agreements to fulfil this coordination requirement and may enter into new agreements where necessary, prior to beginning RC operations.

[12] As indicated in the IRO-014-3 Reliability Standard.

### 4.2.3 Certification Process

WECC is the administrator appointed by the BCUC to assist the BCUC in carrying out the assessment of registration criteria and administration of Reliability Standards. BC Hydro submitted its application to register as an RC in B.C. via the WECC website on September 4, 2018. BC Hydro has also had preliminary discussions with WECC regarding the RC registration process framework in B.C. including discussions on RC registration assurance processes and whether or not certification may be required in B.C.

The BCUC may develop further policies, procedures or guides necessary to carry out the registration in an efficient manner, consistent with the Registration Manual. BC Hydro is not subject to the NERC Rules of Procedure and there is currently no requirement for certification in the BCUC Rules of Procedure. The NERC Rules of Procedure require an Organization Certification Program[13] which is defined as:

> "The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational."

NERC delegates the certification process to the Regional Entities (for example, WECC for the Western Interconnection).

In the B.C. MRS Program, BC Hydro's registration as a BA and as TOP was accepted without certification on a grandfathered basis with the completion of questionnaires. When the AESO became the RC for Alberta, a team from WECC and NERC completed an assurance review to assess the AESO's capability to

[13] NERC Rules of Procedure, section 501; https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20180719.pdf.

comply with the MRS in effect in Alberta. As a result, AESO is recognised as an entity “providing [RC] services consistent with Alberta legislation”,[14] in the Western Interconnection.

BC Hydro’s certification options are described below in Table 4–2.

**Table 4–2 BC Hydro Certification Options**

| Certification Option | Description | Advantages | Disadvantages |
|---|---|---|---|
| No certification. Self-assessment conducted by BC Hydro | BC Hydro establishes the RC function and performs a self- assessment using the Reliability Standard Audit Worksheets (**RSAW**) for those Reliability Standards applicable to RC which it then submits to the BCUC for review. | Little impact on BC Hydro implementation timeline. | No WECC review of BC Hydro’s RC capabilities prior to registration. |
| Assurance review | A modified certification process focused on the new requirements associated with the RC role and conducted by WECC with an onsite visit to BC Hydro. | Provides more rigour and confidence for the BCUC than a self-assessment. | Risk of impact to BC Hydro’s RC implementation timeline. |
| Full certification | Full certification conducted by WECC with onsite visit. | Provides highest level of assessment of RC capability prior to go-live. | Risk that WECC will not have resources to conduct full certification of BC Hydro and risk of impacting BC Hydro’s RC implementation timeline. |

BC Hydro recommends that an RC assurance review be conducted by WECC in advance of BC Hydro’s RC go-live date, similar to the process AESO underwent when it took on RC responsibilities. In addition, BC Hydro will be participating in a triennial onsite compliance audit by WECC in 2020 during which compliance with the RC function Reliability Standards will be further demonstrated.

[14] https://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx.

Appendix B contains the list of the MRS requirements that would apply to the RC function within B.C at the time of go-live in September 2, 2019. As a BA and TOP, BC Hydro already is subject to many of these requirements. Any new requirements that BC Hydro would need to meet in performing the role of RC could form the basis for the assurance review.

### 4.2.4 Standards of Conduct

All employees of BC Hydro that are actively involved in real-time transmission or marketing functions, or who have access to non-public transmission function information, are bound by an existing BC Hydro Standards of Conduct that prevents non-public transmission information from being released to market function employees before it is publicly available. Any new staff joining the RC team will also be bound by this Standards of Conduct. In addition, BC Hydro proposes that, if deemed necessary by the BCUC, it will adhere to a RC Standards of Conduct in a form adopted by the BCUC for use in B.C. and substantially similar to the NERC Reliability Coordinator Standards of Conduct, attached for reference as Appendix C.

### 4.2.5 Software, Licensing, and Shared Services

The software tools required to implement the needs of an RC are not significantly different from those used presently by BC Hydro in its role as BA for the province or in implementing other functional roles such as TOP and GOP. To provide the wide area view required by the RC, some modification and enhancements to BC Hydro’s existing Advanced Applications will be required. BC Hydro has reviewed the requirements of the RC related Reliability Standards to identify required enhancements.

The tools required to implement the tasks performed by the RC function, include:

1. Wide Area Visualization tool: an add-on to BC Hydro’s existing Energy Management System to facilitate wide-area analysis and visualization of system limits within B.C. and beyond the provincial footprint.

2. Network Model: BC Hydro's electrical representation of the Western Interconnection will require additional licensing and need to be enhanced to provide more granular modeling of transmission topologies that are external to B.C. and critical to providing a comprehensive wide area view. BC Hydro has contracted with Powertech Labs to support this enhancement and validate that the resulting model is suitable to represent the Western Interconnection.

3. BC Hydro's Outage Management Software: this tool will need some enhancements to facilitate an RC outage assessment and approval process as well as to facilitate RC to RC sharing of outage data, and as a primary RC logging tool.

4. Shared Services/Externally Hosted Applications: The RCs operating in the Western Interconnection will need to ensure sustainment of some of the existing PEAK toolset to support RC capabilities and other aspects of reliable system operations in the Western Interconnection. These solutions will include data sharing platforms as well as energy accounting tools. BC Hydro is working with other prospective RCs to establish the details to support sustainment of these services.

## 4.3 Cost and Schedule

### 4.3.1 Start-Up and Annual Costs

Operating and Maintenance costs for BC Hydro to implement the RC function are primarily made up of labour costs with some software licensing, shared services, training, legal and travel costs. Costs can be separated into start-up costs, primarily in Fiscal 2019, and ongoing annual costs for Fiscal 2020 and beyond, as shown in Table 4–3 below. The start-up cost and a portion of Fiscal 2020's annual costs will be incremental to the PEAK dues that BC Hydro is obligated to pay until September 2, 2019. Unknown at this time are BC Hydro's share of any incremental PEAK costs that may be associated with the wind down of their operations.

**Table 4–3 Estimated Capital and Operating and Maintenance Costs**

| | Start-Up Cost ($ million) | Ongoing Annual Cost ($ million) |
|---|---|---|
| BC Hydro Staff | 0.15 | 2.14 |
| External project management | 0.20 | 0.00 |
| Consulting fees | 0.40 | |
| Software Purchases, Licensing, and Shared Services | 0.48 | 0.28 |
| Training – non salary | 0.06 | 0.00 |
| Legal | 0.15 | 0.00 |
| Travel | 0.13 | 0.05 |
| Building and equipment | 0.20 | 0.04 |
| Total before Contingency | 1.77 | 2.51 |
| Start-up Contingency (10-30%) | 0.18 – 0.53 | - |
| Ongoing Contingency (10%) | - | 0.25 |
| Total Including Contingency | 1.95 – 2.30 | 2.76 |

Given the compressed timeline to implement this project and the uncertainties associated with the wind down of PEAK, a contingency amount ranging from 10 to 30 per cent has been allocated to all the start-up project components. Since the bulk of the ongoing costs are related to labour, a lower contingency of 10 per cent has been applied.

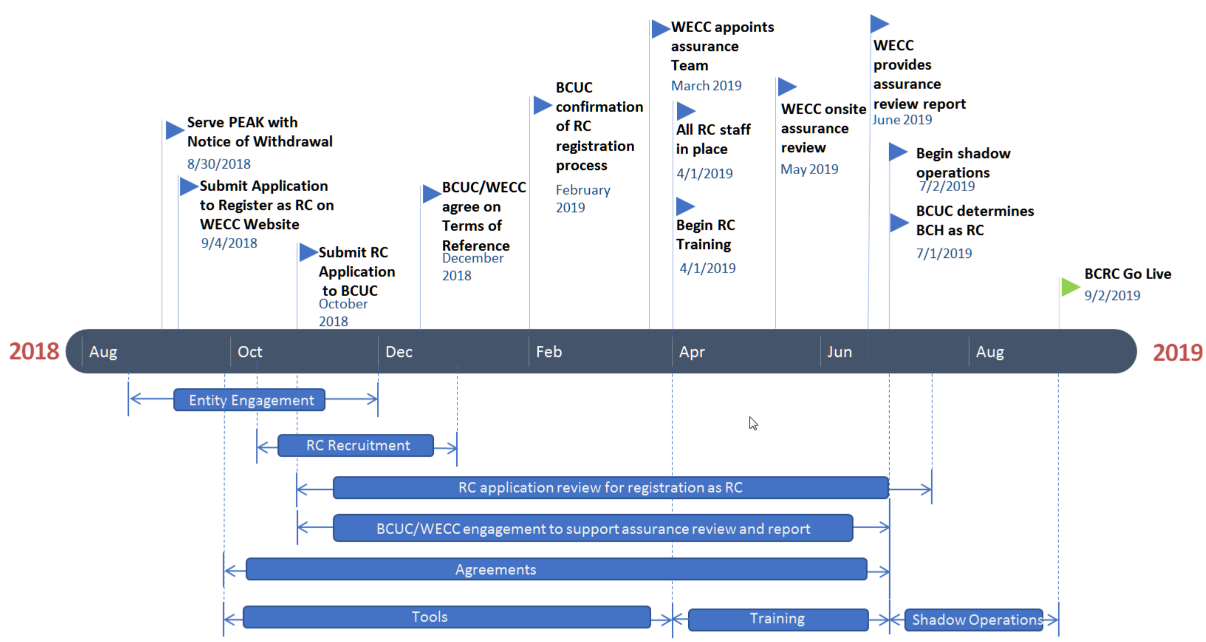
### 4.3.2 Project Schedule

The recent announcement that PEAK would be winding down operations by the end of 2019 has left many utilities in the WECC region with a short time horizon to decide on a RC provider. Utilities presently have a choice of joining either CAISO or SPP, or self-providing. For BC Hydro to successfully launch an RC service by September 2, 2019 a series of activities internal and external to BC Hydro will be undertaken as described below.

#### *4.3.2.1 Schedule and Milestones*

Figure 4–2 and Table 4–4 below set out the key milestones and activities necessary for BC Hydro to implement an RC service for B.C. by September 2, 2019. The milestones and activities indicated will ensure BC Hydro is ready to assume compliance for RC services by the September date. Initial efforts will be focused on ensuring there is sufficient support from registered entities for BC Hydro to take on RC services for B.C. Entity engagement is discussed in detail in Chapter 5. In parallel with this effort, BC Hydro has initiated recruitment for the RC team and is working on extending the operating tools and technologies to meet the requirements set out within the various RC Reliability Standards. This will be followed by RC training, a WECC assurance review, and a period of shadow operations to ensure BC Hydro is ready to provide RC services.

**Figure 4–2 Schedule and Milestones**



1 **Table 4–4 Key Milestones and Activities**

| Key milestone/activities | Date | Supplemental Description |
|---|---|---|
| Entity engagement (Activity) | August 2018 – December 2018 | Gather feedback from B.C. registered entities |
| Serve PEAK with Notice of Withdrawal (Milestone) | August 30, 2018 | Completed |
| Submit application to register as RC on WECC website (Milestone) | September 4, 2018 | Completed |
| Submit BC Hydro's filing to the BCUC in support of its application for the RC function with WECC (Milestone) | October 2018 | Completed |
| RC recruitment (Activity) | October 2018 – December 2018 | Interview and selection process for all RC staff roles |
| RC application review (Activity) | October 2018 – February 2019 | BCUC reviews this filing in support of application for RC registration |
| Tools (Activity) | October 2018 – April 1, 2019 | Build and configure tools to support RC capabilities |
| Agreements (Activity) | October 2018 – June 2019 | Establish all necessary data sharing and entity coordination agreements |
| BCUC/WECC engagement to support assurance review and report (Activity) | October 2018 – June 2019 | Work with BCUC/WECC to plan for and conduct and complete the assurance review |
| BCUC/WECC agree on Terms of Reference (Milestone) | December 2018 | BCUC and WECC agree on Terms of Reference for assurance review |
| BCUC confirmation of RC registration process (Milestone) | February 2019 | |
| WECC appoints assurance team (Milestone) | March 31, 2019 | WECC finalizes participants to support assurance review |
| All RC staff in place (Milestone) | April 1, 2019 | |
| Begin RC training (Milestone) | April 1, 2019 | |
| Training (Activity) | April 2019 – June 2019 | Provide training to new RC staff and existing staff |
| WECC onsite assurance review (Milestone) | May 2019 | WECC leads assurance visit to review RC capabilities |
| WECC provides assurance review report (Milestone) | June 2019 | WECC provides assurance report to BCUC |
| BCUC determines BC Hydro as RC effective September 2, 2019 (Milestone) | July 1, 2019 | BCUC may also rescind its recognition of PEAK as the RC |
| Begin shadow operations (Milestone) | July 2, 2019 | |
| Shadow operations (Activity) | July 2, 2019 – September 1, 2019 | RC shadow operations with PEAK for two months before go-live |
| B.C. RC go-live (Milestone) | September 2, 2019 | |

In parallel with the BCUC review of this filing BC Hydro will be developing tools, processes, and hiring and training staff in order to be ready for an assurance review as determined by the BCUC. Ideally this review would take place following the initial regulatory review and only once enough staff is in place and tools and processes were sufficiently developed to demonstrate to the reviewers that BC Hydro is capable of providing RC Services. This is expected to occur by May 2019. Completion of the assurance review report in June 2019 together with the review of this filing and BC Hydro's RC registration application could then support the BCUC in recognizing BC Hydro as the RC for B.C. by July 1, 2019 with an effective date of September 2, 2019. Between July and September 2019 BC Hydro RC staff would run shadow RC operations with PEAK still being the official RC.

#### 4.3.3 Scheduling Constraints and Considerations

Scheduling constraints are limitations that affect the start or end dates of an activity. There are two constraints and considerations that could affect the schedule:

1. PEAK's budget for calendar 2019 has increased by 26 per cent to account for wind down costs leading to their closure on December 31, 2019. A large part of this increase is to provide financial incentives for staff to remain with PEAK until closure. Despite this incentive there is a risk that staff attrition throughout 2019 may lead to PEAK not being able to provide RC services to its members for the entire year. This could put all members in a position of having no RC for a period of time until their new RC is ready to provide RC services. In BC Hydro's case, should PEAK close down before September 2, 2019, BC Hydro may have to apply to the BCUC for a variance on compliance with RC-related Reliability Standards, as BA and TOP, until such time that BC Hydro is able to provide the service.
2. In 2019, WECC will be conducting certifications of CAISO and SPP as well as the assurance review for BC Hydro. While the duration of the assurance review is likely to be less than one week, the production of a report assessing

BC Hydro's readiness to take on the RC function in B.C. could take several weeks based on past audit experience. Delays in reporting on the assurance review or any corrective measures that need to be implemented as a result of the review could also delay the approval of the RC application and ultimately the go-live date.

Further discussion of risks that might affect the overall project can be found in Chapter 6.

## 4.4 Impacts on Registered Entities

The process of BC Hydro taking on the role of RC for B.C. should result in minimal operational impacts for registered entities within B.C. Historically BC Hydro has coordinated with PEAK and its predecessor RCs for nearly all aspects of reliability affecting the province and registered entities in B.C.

As RC, BC Hydro will be tasked with developing and completing processes related to day-ahead and real-time assessments for the B.C. footprint. At this stage we anticipate these processes to be similar to the PEAK operating processes. Many of these processes will require engagement with B.C. registered entities and the other RCs that will be operating in the Western Interconnection before they can be finalized.

PEAK membership and services fees for RC services for the B.C. Balancing Authority area have been funded to date by BC Hydro. Presently, BC Hydro is not planning on recovering costs from registered entities in B.C. for providing RC services. If in the future, BC Hydro or the BCUC determines that it may be appropriate to pass these costs through to registered entities in B.C., any provisions necessary for BC Hydro to collect costs would only be considered following a fair and public process.

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# BC Hydro MRS Reliability Coordinator
# Registration Filing

# Chapter 5

## Stakeholder Engagement

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## 5.1 Introduction

This chapter summarizes the stakeholder engagement undertaken prior to this filing, during the development of the RC service, and once the RC service is in effect. Stakeholders include the B.C. registered entities, BCUC, WECC as BCUC's administrator, the existing and prospective RCs for the Western Interconnection and B.C. Government.

## 5.2 Engagement Participants

**Table 5–1 Registered Entities in B.C.**

| | |
|---|---|
| Bear Mountain Wind Limited Partnership (BMWL) | 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, West Fraser Mills Ltd. (QUES) |
| Catalyst Paper - Powell River Division (CPPR) | Rio Tinto Alcan (RTA) |
| Coast Mountain Hydro Limited Partnership (CMHL) | Teck Metals Ltd (TECK) |
| Dokie General Partnership (DGP) | Toba Montrose General Partnership (TMGP) |
| Encana (ENCA) | Tolko Industries Limited (TIL) |
| FortisBC Inc. (FBC) | V.I. Power Limited Partnership (VIPL) |
| Howe Sound Pulp & Paper Corporation (HSPP) | WESCUP (WESC) |
| Innergex Renewable Energy Inc. (CWEI) | West Fraser Mills Ltd. (WFM) |
| Intercontinental Pulp Mill (IPML) | |

**Table 5–2 Other RC Providers and Proposed RC Providers**

| | |
|---|---|
| AESO | SPP |
| PEAK | CAISO |

**Table 5–3 Regulators, Administrators and Government**

| | |
|---|---|
| BCUC | WECC |
| Ministry of Energy, Mines and Petroleum Resources | |

## 5.3 Engagement Activities

### 5.3.1 Engagement with Registered Entities in B.C.

The engagement process was established to ensure communication with the B.C. MRS registered entities and to provide opportunities for entities to engage in the transition of RC services for the province of B.C.

BC Hydro sent an email on August 14, 2018 to the B.C. MRS registered entities listed in Table 5–1. This initial engagement provided the registered entities with an awareness of the current state of RC services in the Western Interconnection, including information on why BC Hydro is considering self-supply of the RC service. As well, all B.C. registered entities were provided with opportunities to comment and ask questions.

Five responses have been received representing seven registered entities as of the time of this filing. Three of five responses expressed a level of support for BC Hydro in performing the RC role, while the other two responses expressed a desire for more engagement with BC Hydro before providing a position. Entities have expressed interest in receiving updates as well as participating in webinars or workshops. Some issues have been raised that could be included in a webinar/workshop agenda or addressed individually with the interested entities for clarification. Specifically entities requested more information on RC roles and responsibilities, confirming entity data-sharing obligations, ensuring independence of the RC function, providing more information on CAISO as an option, and the need for independent evaluation of BC Hydro's RC capabilities.

Meetings were also held on September 6, 2018 and October 12, 2018 with FortisBC as the other major TOP in B.C. to provide a verbal summary of BC Hydro's plans and solicit direct feedback. These meetings provided an opportunity to inform operational and compliance staff to allow them to consider impacts to FortisBC's interests. Following these meetings, it was agreed that FortisBC would work with BC Hydro during development of the RC service, as they are the registered entity that currently has the most interactions with BC Hydro for day-ahead and real-time issues and will be subject to procedures developed by BC Hydro as RC.

Further engagement is planned for all entities during the development of the RC service and supporting processes prior to the RC ‘go-live’ date. This may involve periodic emails, conference calls and webinars to provide entities with further information on questions or concerns that have been raised. Once the RC service has been established, continued engagement will occur routinely with the B.C. registered entities.

### 5.3.2 Engagement with RC Providers and Proposed RC Providers

BC Hydro’s engagement with existing and proposed RC providers began in June 2018. As BC Hydro was considering the options for RC service, RC coordination meetings were held to discuss the transition of customers from PEAK to CAISO and SPP. BC Hydro plans to continue participating in these meetings to contribute to discussions and decisions with respect to the wind down of PEAK and the establishment of new RCs within the Western Interconnection. These meetings will continue through 2019 as the transition to new RC providers occurs.

Another key aspect of engagement with RC providers is the development of BC Hydro’s coordination agreements. These agreements will need to be in place prior to BC Hydro’s RC ‘go-live’ date. BC Hydro has contacted AESO to establish its first RC coordination agreement. We will continue to work with the other RC’s to establish and agree on the terms and timelines for these agreements.

### 5.3.3 Engagement with Regulators, Administrators, and Government

BC Hydro met with the BCUC on July 24, 2018 to provide a summary of BC Hydro’s assessment of RC options for B.C. and to discuss potential next steps in establishing BC Hydro as the RC for B.C. Since then, there have been updates provided to the BCUC to inform them of BC Hydro’s notice of withdrawal from PEAK and submission of the RC registration with WECC.

WECC has been involved in the RC coordination meetings that began earlier in 2018 involving PEAK, CAISO, SPP and AESO. BC Hydro first participated in these meetings in June 2018 and since then has been communicating with WECC to keep them apprised of BC Hydro's position. WECC was formally advised of BC Hydro's intention to register as RC for B.C. with the submission of the application for registration through the WECC website on September 4, 2018. BC Hydro has been working with WECC to determine the criteria for evaluation of BC Hydro's RC capabilities.

Ongoing engagement with the BCUC and WECC is expected throughout the RC application review process and is covered in more detail in section 4.3.2.1.

In October 2018 BC Hydro issued a briefing note to the B.C. Government indicating that it would be pursuing registration as RC for the province of B.C.

BC Hydro MRS Reliability Coordinator

Registration Filing

# Chapter 6

## Risk Management

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# List of Tables

## 6.1 Introduction

This chapter provides a summary of the key Project related risks, plans to manage these risks and any residual risks. The key risks associated with the Project are considered within the phases of the Project life cycle:

- Risks during the 'start-up' period of the project prior to becoming operational. Risks during this phase can be further identified as 'internal' or 'external' risks.
- Compliance risks for new Reliability Standards and requirements once RC operations commence.

The risks and treatment plans are discussed in greater detail throughout the remainder of this chapter.

## 6.2 Start-up Risks

Most of the start-up risks are driven by the short timeline required to implement the RC role and the need to have people, process, and technology changes in place to begin parallel operations by summer 2019 and transition to independent operations by September 2019. These risks can be further characterized as 'internal' or 'external' depending on the primary source of the associated uncertainty. Refer to Table 6–1 for a tabular presentation of the start-up risks, potential impacts, and mitigations.

### 6.2.1 Internal Risks

The primary internal risks are related to human resource requirements during the start-up phase of the project. These include the need to fill the new RC roles in a short time frame and the dependency on the availability of subject matter experts to support project deliverables.

- **Staffing uncertainty during transition of existing staff into RC roles** – It is expected that most RC roles will be filled by BC Hydro internal staff currently performing other functions. As they transition into RC roles there may be impacts to the departments in which they previously worked until those positions are backfilled. These potential impacts need to be managed to ensure BC Hydro continues to deliver on its existing commitments.

- Mitigation: Recruitment will take place early in the project to ensure that transitions from other BC Hydro groups can be closely coordinated and allow time for transfer of duties to other staff.

- **Availability of key internal BC Hydro resources to support project deliverables** – Due to the short project timeframe, the availability of key resources is fundamental to meeting the project schedule. Many of the project tasks require specialized skills. For example, development of training for the RC roles is highly dependent on a small number of subject matter experts in modelling, tools and simulation.

  - Mitigation: Project planning will account for availability of key staff to ensure the project schedule is not adversely impacted. As well, additional resources will be trained to provide support for key deliverables.

### 6.2.2 External Risks

The main external risks involve schedule delays related to agreements, data exchange, shared services tools, and regulatory approvals. If not mitigated, these risks could lead to delays and cost escalation.

- **Delay in establishing agreements** – BC Hydro will need to establish RC-to-RC agreements with all RCs operating in the Western Interconnection. While templates exist, the number of agreements and the short timeline poses a risk to ensuring these are all in place in a timely manner before BC Hydro is operating as RC. These agreements will address issues such as operations coordination, data exchange, communication protocols, and emergency procedures.

  - Mitigation: BC Hydro will be working with AESO, CAISO and SPP to establish the terms for agreements over the next few months to ensure there is sufficient time to finalize and sign agreements to support data exchange and preparation of BC Hydro procedural documents (i.e., policies and training).

- **Data Exchange with other RC's in the Western Interconnection** – to support the RC function, BC Hydro will need to agree on the required data exchange with all RCs operating in the Western Interconnection. The scope of data required will not be finalized until agreements have been established with other RCs. Data exchange is required to support the operational analyses required for RC operations.

  - Mitigation: The focus will be on leveraging existing data exchange agreements and protocols to mitigate costs and schedule impacts. As well, work will begin early to establish test environments and new agreements with entities to support orderly transition of data requirements.

- **Uncertainty of sustainment of existing PEAK RC tools post wind down** – PEAK RC provides a number of tools today that are of interest to many of the RC's and BAs in the Western Interconnection that will continue to operate after PEAK dissolves. These include Enhanced Curtailment Calculator (used to determine energy curtailment amounts to address system overloads) and Western Interchange Tool (used for accounting of scheduled and actual interchange values), as well as other tools.

  - Mitigation: BC Hydro is currently participating in discussions with PEAK, AESO and the other future RCs to clarify which tools will be sustained and by whom. This will provide an early understanding of what to plan for in regards to providing the required capabilities and determining associated costs.

- **Delay in regulatory approvals for self-supply of RC services** – BC Hydro will need to demonstrate to the BCUC that it has the ability to provide the RC service. It is expected that this will be achieved with information contained within this filing, participation in any further regulatory processes, and confirmation of BC Hydro's RC capabilities through an assurance process.
  - Mitigation: Filing of this Submission to the BCUC in October 2018 to allow for the earliest consideration of the detailed RC registration requirements. In addition, BC Hydro will work with the BCUC and WECC to determine a scope and time frame for WECC to conduct an assurance review of BC Hydro's RC capabilities.
- **PEAK unable to sustain operations until December 2019** – There is a risk that PEAK may not have the resources required to sustain RC operations as new RCs are established and become able to assume the RC responsibilities for the PEAK area. If this occurs, it will result in loss of RC oversight for the majority of the Western Interconnection, resulting in weakened coordination and management of regional risks and non-compliance with Reliability Standards.
  - Mitigation: BC Hydro plans to have RC capabilities in place in B.C. by July 1, 2019 to support two months of shadow operations with PEAK before transition. BC Hydro will continue working with PEAK, CAISO, SPP, and AESO on transitional issues such as tools, agreements, responsibilities to support coordination amongst the future RCs in the lead up to PEAK's wind down. In addition, PEAK has increased their operating budget for 2019 by 26 per cent to fund wind down costs and provide financial incentives for staff to remain until the end of 2019.

**Table 6–1 Start-up Risks (Internal and External)**

| Risk | Impact | Mitigation | Other (cost etc.) |
|---|---|---|---|
| Staffing uncertainty during transition of existing staff into RC roles (Internal) | Delays in other BC Hydro work | Early recruitment for RC roles<br>Coordinate staged transition of staff into RC roles | Potential cost impacts if not all staff in place as per schedule (i.e., overtime, additional training) |
| Availability of key internal BC Hydro resources to support project deliverables (Internal) | Delays in project deliverables | Project planning accounts for key resource dependencies<br>Train additional resources to support key deliverables | |
| Delays in agreements with other RCs (External) | Slippage in schedule and potential issues with data exchange with other RCs | Prioritize working with AESO, CAISO and SPP on establishing agreements. | |
| Data exchange requirements not in place for model updates and real-time monitoring. (External) | Unable to perform all required analyses | Leverage existing agreements to support expanded data exchange<br>Establish new agreements with entities to support orderly transition of data requirements | Uncertain costs to establish new data transfer |
| Uncertainty of sustainment of existing PEAK RC tools post wind down | Unknown cost impacts to provide required RC capabilities | Continue working with PEAK, CAISO, SPP, and AESO on transitional issues. | Cost impacts will become more clear as future RC’s agree on direction |
| Delay in regulatory approval to support registration as RC. (External) | Slippage in RC implementation schedule<br>Uncertainty in RC service for B.C. | Work with BCUC and WECC to clarify evaluation of RC capabilities | |
| PEAK unable to sustain operations until December 2019. (External) | Potential lack of RC for most of WECC region until CAISO, SPP, BC Hydro start up<br>Weakened coordination and management of regional risks and non-compliance with MRS | Plan to have RC capabilities in place in B.C. by July 1 to support two months parallel operations before transition<br>Continue working with PEAK, CAISO, SPP, and AESO on transitional issues such as tools, agreements, responsibilities. | |

## 6.3 Ongoing Risks

The ongoing risks are internal to BC Hydro and are inherent to taking on the expanded role of the RC and the associated Reliability Standards and requirements. BC Hydro has defined the ongoing risk in the following two areas. Refer to Table 6–2 for a tabular presentation of the ongoing risks, potential impacts, and mitigations.

- **Operational compliance risk** – As BC Hydro will be operating as the RC for B.C., there will be an increase in the number of MRS requirements to comply with, resulting in increased compliance risk.
  - ▶ Mitigation: Compliance is achieved by meeting the requirements of the Reliability Standards and demonstrated by the collection of evidence. As BC Hydro develops the capabilities to provide RC service, compliance requirements will be embedded in RC operational tools and processes.
- **Modeling requirements for RCs** - IRO Standard 002-5 – WECC has initiated a Reliability Standards Authorization Request to consider options for RC modeling requirements. BC Hydro is participating in the Reliability Standard drafting process but is concerned that the result may not support its preferred modeling methodology. There exists potential that the WECC regional variance currently under development may differ from BC Hydro’s approach to modeling of BES elements in the Western Interconnection and WECC Remedial Action Schemes.
  - ▶ Mitigation: BC Hydro technical staff is participating on the associated WECC -0135 Reliability Standards drafting team.

1 **Table 6–2 Ongoing Risks**

| Risk | Impact | Mitigation | Other (Cost, etc.) |
|---|---|---|---|
| Increased operating liability when BC Hydro is acting as RC | Increased liability when BC Hydro is operating as the RC for province of B.C. (i.e., need to comply with more MRS and financial risk for non-compliance) | Embed compliance activities in RC processes, supported by adequate tools<br>Dedicated resource to oversee compliance requirements and documentation of evidence<br>Initial and ongoing training of RC staff | |
| Uncertainty within WECC over RC modeling issues (External) | WECC MRS may impose modeling requirements that are not appropriate for B.C. | Reliability Standards Drafting team participation | |

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## List of Appendices

# BC Hydro MRS Reliability Coordinator

# Registration Filing

## Appendix A

## WECC Registration Request Form

# Registration Request Form

Please note * are required fields

## Type of Registration Request

Is your company currently listed as a Registered Entity for the WECC Region?* (●) Yes ( ) No

## Requester Contact Information

**Provide your contact information**

| | |
|---|---|
| Full Name* | Paul Choudhury |
| Job Title* | Director, T&D System Operations |
| Email Address* | paul.choudhury@bchydro.com |
| Confirm Email Address* | paul.choudhury@bchydro.com |
| Telephone Number* | 604-455-4204 |
| Fax Number | *000-000-0000* |
| Corporate Website | www.bchydro.com |

## Operational Information

If this is a new facility/operation please specify the date upon which operations have commenced or will commence. If this application pertains to a generator please provide synchronization date.

Specify Multi-Region Operations if applicable.
(Please indicate each Region in which the entity operates and/or own facilities)

| | | | |
|---|---|---|---|
| ALL | ☐ | RFC | ☐ |
| FRCC | ☐ | SERC | ☐ |
| MRO | ☐ | SPP | ☐ |
| NPCC | ☐ | TRE | ☐ |

Will this registration change be requested ( ) Yes (●) No in the other Regions?

***All required fields must be completed before continuing.***

# Registration Change Request Form

## Registered Entity Information

| | |
|---|---|
| Current Registered Entity Name* | British Columbia Hydro and Power Authority |
| Entity Acronym* | BCHA |
| NCR#* | NCR05037 |

## Type of Registration Request

**Specify type of registration request. Select all that apply.**

| | |
|---|---|
| Request to add or deactivate Reliability Functions(s) to your Entity's current request. | ☑ |
| Request to change your Registered Entity's Name/Ownership. | ☐ |
| Request to change your Entity's Footprint. | ☐ |

***All required fields must be completed before continuing.***

# Reliability Function(s) Registration Change Request Form

**Specify which function(s) your Entity wishes to add or deactivate to its current registration and answer the questions that appear completely.**

| | | | |
|---|---|---|---|
| Balancing Authority (BA) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Distribution Provider (DP) | ◉ Not Applicable | ○ Add | ○ Deactivate |

To request a change to your current registration from Distribution Provider to Underfrequency Load Shedding-Only Distribution Provider select the 'Add' radio button above and completethe information for Add DP Function below. In the General Comments area, enter a comment indicating you are requestingregistration as a UFLS-Only DP.

| | | | |
|---|---|---|---|
| Generator Owner (GO) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Generator Operator (GOP) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Interchange Authority (IA) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Planning Authority (PA) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Purchase-Selling Entity (PSE) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Reliability Coordinator (RC) | ○ Not Applicable | ◉ Add | ○ Deactivate |
| Reserve Sharing Group (RSG) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Resource Planner (RP) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Transmission Owner (TO) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Transmission Operator (TOP) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Transmission Planner (TP) | ◉ Not Applicable | ○ Add | ○ Deactivate |
| Transmission Service Provider (TSP) | ◉ Not Applicable | ○ Add | ○ Deactivate |

## Add RC Function

**Please answer the following**

| | | |
|---|---|---|
| Are you the Entity that is the highest level of authority who is responsible for the reliable operation of the bulk electric system, has a 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? | ○ Yes | ◉ No |

| | |
|---|---|
| If No, please specify the reason for this registration request. | BCHA is not presently an RC and wishes to register as RC for the province of British Columbia. |
| Please specify the reason for this request. Select all that apply. | |
| A Transfer of Ownership within the same company, requesting to set up a separate registration under a different NCR ID. | ☐ |
| A cosmetic name change (e.g., no change in corporate structure or parent company). | ☐ |
| Transfer of Assets within the same company, requesting to set up a separate registration under a different NCR ID). | ☐ |
| A result of a transfer of assets or functions to a different company. | ☐ |
| Other (please explain). | The wind-down of PEAK RC in 2019 |

***All required fields must be completed before continuing***

# General Comments and Uploads Registration Request Form

## General Comments and Uploads

**Please provide any additional comments relating to this request.**

*General Comments*

BC Hydro will be supporting this registration request with an application to the British Columbia Utilities Commission that details the capabilities of BC Hydro to perform the RC function for British Columbia as well as options for certification/assurance like processes that might facilitate registration. We anticipate this filing will take place in late September or early October 2018 and we look forward to supporting WECC and the BCUC in this registration process.

## File Uploads

**Please upload any related files to this request.**

Note: the file size limit per request is **25 MB**. If your files exceed this limit, please contact WECC Program Administration via email at programadmin@wecc.biz for assistance.

Suggested file types listed below:

- One-Line Diagram(s)
- Transfer of ownership document(s) (I.E., agreements, contracts, etc.)
- CFR Agreement(s)
- JRO Agreement(s)
- Other

No file attached

*Please click "insert item" for additional documents*

***All required fields must be completed before submitting.***

# BC Hydro MRS Reliability Coordinator Registration Filing

# Appendix B

## List of Reliability Standards Applicable to Reliability Coordinator Function and Effective in B.C. as of September 2, 2019

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Nov-10 | BAL-004-0 | R1. | Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor. | |
| 01-Nov-10 | BAL-004-0 | R2. | The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure. | |
| 01-Nov-10 | BAL-004-0 | R4. | Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations. | |
| 01-Nov-10 | BAL-004-0 | R4.1 | Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-18 | CIP-002-5.1a | R1. | R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [Violation Risk Factor: High][Time Horizon: Operations Planning]<br>i. Control Centers and backup Control Centers;<br>ii. Transmission stations and substations;<br>iii. Generation resources;<br>iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;<br>v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and<br>vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.<br>1.1. Identify each of the high impact Bulk Electric System (**BES**) Cyber Systems according to Attachment 1, section 1, if any, at each asset;<br>1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, section 2, if any, at each asset; and<br>1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, section 3, if any (a discrete list of low impact BES Cyber Systems is not required). | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-18 | CIP-002-5.1a | R2. | R2. The Responsible Entity shall:<br>2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and<br>2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1. | Yes |
| October 1, 2018 | CIP-003-5 | 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]<br>1.1 Personnel & training (CIP-004);<br>1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access;<br>1.3 Physical security of BES Cyber Systems (CIP-006);<br>1.4 System security management (CIP-007);<br>1.5 Incident reporting and response planning (CIP-008);<br>1.6 Recovery plans for BES Cyber Systems (CIP-009);<br>1.7 Configuration change management and vulnerability assessments (CIP-010);<br>1.8 Information protection (CIP-011); and<br>1.9 Declaring and responding to CIP Exceptional Circumstances. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| October 1, 2018<br><br>R2.2, R2.3: Adoption held in abeyance pending the adoption of CIP-003-7. | CIP-003-5 | R2. | Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]<br>2.1 Cyber security awareness;<br>2.2 Physical security controls;<br>2.3 Electronic access controls for external routable protocol connections and Dial-up Connectivity; and<br>2.4 Incident response to a Cyber Security Incident.<br>An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required. | Yes |
| 01-Oct-18 | CIP-003-5 | R3. | Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. | Yes |
| 01-Oct-18 | CIP-003-5 | 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 Manage 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. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-18 | CIP-004-6 | R1. | Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-6 Table R1 – Security Awareness Program.* (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-004-6 | R2. | Each Responsible Entity shall implement one or more cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-6 Table R2 – Cyber Security Training Program*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-004-6 | R3. | Each Responsible Entity shall implement one or more documented personnel risk assessment program(s) to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-6 Table R3 – Personnel Risk Assessment Program*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-004-6 | R4. | Each Responsible Entity shall implement one or more documented access management program(s) that collectively include each of the applicable requirement parts in *CIP-004-6 Table R4 – Access Management Program.* (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-004-6 | R5. | Each Responsible Entity shall implement one or more documented access revocation program(s) that collectively include each of the applicable requirement parts in *CIP-004-6 Table R5 – Access Revocation*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-005-5 | R1. | Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-5 Table R1 – Electronic Security Perimeter*. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-18 | CIP-005-5 | R2. | Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-5 Table R2 – Interactive Remote Access Management*. | Yes |
| 01-Oct-18 | CIP-006-6 | R1. | Each Responsible Entity shall implement one or more documented physical security plan(s) that collectively include all of the applicable requirement parts in *CIP-006-6 Table R1 – Physical Security Plan*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-006-6 | R2. | Each Responsible Entity shall implement one or more documented visitor control program(s) that include each of the applicable requirement parts in *CIP-006-6 Table R2 – Visitor Control Program.* (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-006-6 | R3. | Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing program(s) that collectively include each of the applicable requirement parts in *CIP-006-6 Table R3 – Maintenance and Testing Program*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-007-6 | R1. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R1 – Ports and Services*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-007-6 | R2. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R2 – Security Patch Management*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-007-6 | R3. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R3 – Malicious Code Prevention*. (please refer to the standard for sub-requirements) | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-18 | CIP-007-6 | R4. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R4 – Security Event Monitoring*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-007-6 | R5. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-007-6 Table R5 – System Access Controls*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-008-5 | R1. | Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5 Table R1 – Cyber Security Incident Response Plan Specifications*. | Yes |
| 01-Oct-18 | CIP-008-5 | R2. | Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-5 Table R2 – Cyber Security Incident Response Plan Implementation and Testing.* | Yes |
| 01-Oct-18 | CIP-008-5 | R3. | Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-5 Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. | Yes |
| 01-Oct-18 | CIP-009-6 | R1. | Each Responsible Entity shall have one or more documented recovery plan(s) that collectively include each of the applicable requirement parts in *CIP-009-6 Table R1 – Recovery Plan Specifications*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-009-6 | R2. | Each Responsible Entity shall implement its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-6 Table R2 – Recovery Plan Implementation and Testing. (please refer to the standard for sub-requirements)* | Yes |

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| 01-Oct-18 | CIP-009-6 | R3. | Each Responsible Entity shall maintain each of its recovery plan(s) in accordance with each of the applicable requirement parts in *CIP-009-6 Table R3 – Recovery Plan Review, Update and Communication*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-010-2 | R1. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-2 Table R1 – Configuration Change Management*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-010-2 | R2. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-2 Table R2 – Configuration Monitoring.* (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-010-2 | R3. | Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-2 Table R3– Vulnerability Assessments*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-010-2 | R4. | Each Responsible Entity, for its high impact and medium impact BES Cyber Systems and associated Protected Cyber Assets, shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) for Transient Cyber Assets and Removable Media that include the sections in Attachment 1. | Yes |
| 01-Oct-18 | CIP-011-2 | R1. | Each Responsible Entity shall implement one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-2 Table R1 – Information Protection*. (please refer to the standard for sub-requirements) | Yes |
| 01-Oct-18 | CIP-011-2 | R2. | Each Responsible Entity shall implement one or more documented process(es) that collectively include the applicable requirement parts in *CIP-011-2 Table R2 – BES Cyber Asset Reuse and Disposal*. (please refer to the standard for sub-requirements) | Yes |

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| 01-Oct-17 | COM-001-3 | R1. | Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): | |
| 01-Oct-17 | COM-001-3 | 1.1. | All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. | |
| 01-Oct-17 | COM-001-3 | 1.2. | Each adjacent Reliability Coordinator within the same Interconnection. | |
| 01-Oct-17 | COM-001-3 | R2. | Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: | |
| 01-Oct-17 | COM-001-3 | 2.1. | All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. | |
| 01-Oct-17 | COM-001-3 | 2.2. | Each adjacent Reliability Coordinator within the same Interconnection. | |
| 01-Oct-18 | COM-001-3 | R9. | Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within two hours. | Yes |
| 01-Oct-18 | COM-001-3 | R10. | Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. | Yes |

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| 01-Oct-18 | COM-001-3 | R12. | Each Reliability Coordinator, Transmission Operator, Generator Operator, and Balancing Authority shall have internal Interpersonal Communication capabilities for the exchange of information necessary for the Reliable Operation of the BES. This includes communication capabilities between Control Centers within the same functional entity, and/or between a Control Center and field personnel. | Yes |
| 01-Apr-17 | COM-002-4 | R1. | Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: | Yes |
| 01-Apr-17 | COM-002-4 | R1.1 | Require its operating personnel that issue and receive an oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. | Yes |
| 01-Apr-17 | COM-002-4 | R1.2 | Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions:<br>Confirm the receiver’s response if the repeated information is correct.<br>Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver.<br>Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. | Yes |
| 01-Apr-17 | COM-002-4 | R1.3. | Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions:<br>Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct.<br>Request that the issuer reissue the Operating Instruction. | Yes |

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| 01-Apr-17 | COM-002-4 | R1.4 | Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. | Yes |
| 01-Apr-17 | COM-002-4 | R1.5. | Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. | Yes |
| 01-Apr-17 | COM-002-4 | R1.6. | Specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction. | Yes |
| 01-Apr-17 | COM-002-4 | R2. | Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. | Yes |
| 01-Apr-17 | COM-002-4 | R4. | Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every 12 calendar months: | Yes |
| 01-Apr-17 | COM-002-4 | R4.1. | Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. | Yes |
| 01-Apr-17 | COM-002-4 | R4.2 | Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary. | Yes |

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| 01-Apr-17 | COM-002-4 | R5. | Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either:<br>• Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6).<br>• Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or<br>• Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. | Yes |
| 01-Apr-17 | COM-002-4 | R7. | Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. | Yes |
| 01-Oct-17 | EOP-004-3 | R1. | Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2-3 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). | Yes |
| 01-Oct-17 | EOP-004-3 | R2. | Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 p.m. local time on Friday to 8 a.m. Monday local time). | Yes |
| 01-Oct-17 | EOP-004-3 | R3. | Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. | Yes |

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| 01-Aug-14 | EOP-006-2 | R1. | Each Reliability Coordinator shall have 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 area of the 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: | |
| 01-Aug-14 | EOP-006-2 | 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. | |
| 01-Aug-14 | EOP-006-2 | R1.2. | Operating Processes for restoring the Interconnection. | |
| 01-Aug-14 | EOP-006-2 | R1.3. | Descriptions of the elements of coordination between individual Transmission Operator restoration plans. | |
| 01-Aug-14 | EOP-006-2 | R1.4. | Descriptions of the elements of coordination of restoration plans with neighboring Reliability Coordinators. | |
| 01-Aug-14 | EOP-006-2 | R1.5. | 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. | |

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| 01-Aug-14 | EOP-006-2 | R1.6. | Reporting requirements for the entities within the Reliability Coordinator Area during a restoration event. | |
| 01-Aug-14 | EOP-006-2 | R1.7. | Criteria for sharing information regarding restoration with neighboring Reliability Coordinators and with Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. | |
| 01-Aug-14 | EOP-006-2 | 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. | |
| 01-Aug-14 | EOP-006-2 | R1.9. | Criteria for transferring operations and authority back to the Balancing Authority. | |
| 01-Aug-14 | EOP-006-2 | 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. | |
| 01-Aug-14 | EOP-006-2 | R3. | Each Reliability Coordinator shall review its restoration plan within 13 calendar months of the last review. | |
| 01-Aug-14 | EOP-006-2 | R4. | Each Reliability Coordinator shall review their neighboring Reliability Coordinator's restoration plans. | |
| 01-Aug-14 | EOP-006-2 | R4.1. | If the Reliability Coordinator finds conflicts between its restoration plans and any of its neighbors, the conflicts shall be resolved in 30 calendar days. | |
| 01-Aug-14 | EOP-006-2 | R5. | Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area. | |

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| 01-Aug-14 | EOP-006-2 | R5.1. | 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 or disapprove, with stated reasons, the Transmission Operator's submitted restoration plan within 30 calendar days following the receipt of the restoration plan from the Transmission Operator. | |
| 01-Aug-14 | EOP-006-2 | 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 date. | |
| 01-Aug-14 | EOP-006-2 | R7. | Each Reliability Coordinator shall 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. If the restoration plan cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate System restoration. | |
| 01-Aug-14 | EOP-006-2 | 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. | |
| 01-Aug-14 | EOP-006-2 | 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: | |

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| 01-Aug-14 | EOP-006-2 | R9.1. | The coordination role of the Reliability Coordinator. | |
| 01-Aug-14 | EOP-006-2 | R9.2. | Re-establishing the Interconnection. | |
| 01-Aug-14 | EOP-006-2 | 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. | |
| 01-Aug-14 | EOP-006-2 | R10.1. | 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 every two calendar years. | |
| 01-Aug-15 | EOP-008-1 | 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: | Yes |
| 01-Aug-15 | EOP-008-1 | 1.1. | The location and method of implementation for providing backup functionality for the time it takes to restore the primary control center functionality. | Yes |
| 01-Aug-15 | EOP-008-1 | 1.2. | A summary description of the elements required to support the backup functionality. These elements shall include, at a minimum: | Yes |

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| 01-Aug-15 | EOP-008-1 | 1.2.1. | Tools and applications to ensure that System Operators have situational awareness of the BES | Yes |
| 01-Aug-15 | EOP-008-1 | 1.2.2. | Data communications. | Yes |
| 01-Aug-15 | EOP-008-1 | 1.2.3. | Voice communications. | Yes |
| 01-Aug-15 | EOP-008-1 | 1.2.4. | Power source(s). | Yes |
| 01-Aug-15 | EOP-008-1 | 1.2.5. | Physical and cyber security. | Yes |
| 01-Aug-15 | EOP-008-1 | 1.3. | An Operating Process for keeping the backup functionality consistent with the primary control center. | Yes |
| 01-Aug-15 | EOP-008-1 | 1.4. | Operating Procedures, including decision authority, for use in determining when to implement the Operating Plan for backup functionality. | Yes |
| 01-Aug-15 | EOP-008-1 | 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. | Yes |
| 01-Aug-15 | EOP-008-1 | 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: | Yes |
| 01-Aug-15 | EOP-008-1 | 1.6.1. | A list of all entities to notify when there is a change in operating locations. | Yes |

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| 01-Aug-15 | EOP-008-1 | 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. | Yes |
| 01-Aug-15 | EOP-008-1 | 1.6.3. | Identification of the roles for personnel involved during the initiation and implementation of the Operating Plan for backup functionality. | Yes |
| 01-Aug-15 | EOP-008-1 | 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. | Yes |
| 01-Aug-15 | EOP-008-1 | 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 primary control center functionality. To avoid requiring a tertiary facility, a backup facility is not required during:<br>* Planned outages of the primary or backup facilities of two weeks or less<br>* Unplanned outages of the primary or backup facilities | |
| 01-Aug-15 | EOP-008-1 | R5. | Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall annually review and approve its Operating Plan for backup functionality. [*Please refer to the standard for update and approval requirements*] | Yes |
| 01-Aug-15 | EOP-008-1 | 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. | Yes |

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| 01-Aug-15 | EOP-008-1 | R7. | Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct and document results of an annual test of its Operating Plan that demonstrates: | Yes |
| 01-Aug-15 | EOP-008-1 | 7.1. | The transition time between the simulated loss of primary control center functionality and the time to fully implement the backup functionality. | Yes |
| 01-Aug-15 | EOP-008-1 | 7.2. | The backup functionality for a minimum of two continuous hours. | Yes |
| 01-Aug-15 | EOP-008-1 | 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. | Yes |
| 01-Oct-16 | EOP-010-1 | R1. | Each Reliability Coordinator shall develop, maintain, and implement a Geo-Magnetic Disturbance (**GMD**) Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include: | |
| 01-Oct-16 | EOP-010-1 | 1.1 | A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area. | |
| 01-Oct-16 | EOP-010-1 | 1.2 | A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area. | |

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| 01-Oct-16 | EOP-010-1 | R2. | Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. | |
| 01-Oct-18 | EOP-011-1 | R3. | The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. | |
| 01-Oct-18 | EOP-011-1 | R3.1. | Within 30 calendar days of receipt, the Reliability Coordinator shall: | |
| 01-Oct-18 | EOP-011-1 | R3.1.1. | Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans; | |
| 01-Oct-18 | EOP-011-1 | R3.1.2. | Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and | |
| 01-Oct-18 | EOP-011-1 | R3.1.3. | Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified. | |
| 01-Oct-18 | EOP-011-1 | R5. | Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. | |
| 01-Oct-18 | EOP-011-1 | R6. | Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. | |

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| 01-Oct-17 | FAC-011-3 | R1. | The Reliability Coordinator shall have a documented methodology for use in developing System Operating Limits (**SOLs**) (**SOL Methodology**) within its Reliability Coordinator Area. This SOL Methodology shall: | |
| 01-Oct-17 | FAC-011-3 | R1.1. | Be applicable for developing SOLs used in the operations horizon. | |
| 01-Oct-17 | FAC-011-3 | R1.2. | State that SOLs shall not exceed associated Facility Ratings. | |
| 01-Oct-17 | FAC-011-3 | R1.3. | Include a description of how to identify the subset of SOLs that qualify as Interconnection Operating Reliability Limits (**IROLs**). | |
| 01-Oct-17 | FAC-011-3 | R2. | The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: | |
| 01-Oct-17 | FAC-011-3 | R2.1. | In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. | |
| 01-Oct-17 | FAC-011-3 | R2.2. | Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, | |
| 01-Oct-17 | FAC-011-3 | R2.2.1. | Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. | |
| 01-Oct-17 | FAC-011-3 | R2.2.2. | Loss of any generator, line, transformer, or shunt device without a Fault. | |
| 01-Oct-17 | FAC-011-3 | R2.2.3. | Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. | |

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| 01-Oct-17 | FAC-011-3 | R2.3. | In determining the system's response to a single Contingency, the following shall be acceptable: | |
| 01-Oct-17 | FAC-011-3 | R2.3.1. | Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. | |
| 01-Oct-17 | FAC-011-3 | R2.3.2. | Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies | |
| 01-Oct-17 | FAC-011-3 | R2.3.3. | System reconfiguration through manual or automatic control or protection actions. | |
| 01-Oct-17 | FAC-011-3 | R2.4. | To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology. | |
| 01-Oct-17 | FAC-011-3 | R3. | The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: | |
| 01-Oct-17 | FAC-011-3 | R3.1. | Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study). | |
| 01-Oct-17 | FAC-011-3 | R3.2. | Selection of applicable Contingencies | |
| 01-Oct-17 | FAC-011-3 | R3.3. | A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. | |

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| 01-Oct-17 | FAC-011-3 | R3.3.1. | This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. | |
| 01-Oct-17 | FAC-011-3 | R3.4. | Level of detail of system models used to determine SOLs. | |
| 01-Oct-17 | FAC-011-3 | R3.5. | Allowed uses of Remedial Action Schemes. | |
| 01-Oct-17 | FAC-011-3 | R3.6. | Anticipated transmission system configuration, generation dispatch and Load level | |
| 01-Oct-17 | FAC-011-3 | R3.7. | Criteria for determining when violating a SOL qualifies as an IROL and criteria for developing any associated IROL $T_v$. | |
| 01-Oct-17 | FAC-011-3 | R4. | The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: | |
| 01-Oct-17 | FAC-011-3 | R4.1. | Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology. | |
| 01-Oct-17 | FAC-011-3 | R4.2. | Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area. | |
| 01-Oct-17 | FAC-011-3 | R4.3. | Each Transmission Operator that operates in the Reliability Coordinator Area. | |
| 01-Jan-11 | FAC-014-2 | R1. | The Reliability Coordinator shall ensure that SOLs, including IROLs, for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. | |

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|---|---|---|---|---|
| 01-Jan-11 | FAC-014-2 | R5. | The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: | |
| 01-Jan-11 | FAC-014-2 | R5.1. | The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information: | |
| 01-Jan-11 | FAC-014-2 | R5.1.1. | Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. | |
| 01-Jan-11 | FAC-014-2 | R5.1.2. | The value of the IROL and its associated Tv. | |
| 01-Jan-11 | FAC-014-2 | R5.1.3. | The associated Contingency(ies). | |
| 01-Jan-11 | FAC-014-2 | R5.1.4. | The type of limitation represented by the IROL (e.g., voltage collapse, angular stability). | |
| 01-Oct-17 | IRO-001-4 | R1. | Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Jan-19 | IRO-002-5 | R1. | Each Reliability Coordinator shall have data exchange capabilities with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for it to perform its Operational Planning Analyses. | |
| 01-Jan-19 | IRO-002-5 | R2. | Each Reliability Coordinator shall have data exchange capabilities, with redundant and diversely routed data exchange infrastructure within the Reliability Coordinator's primary Control Center, for the exchange of Real-time data with its Balancing Authorities and Transmission Operators, and with other entities it deems necessary, for performing its Real-time monitoring and Real-time Assessments. | |
| 01-Jan-19 | IRO-002-5 | R3. | Each Reliability Coordinator shall test its primary Control Center data exchange capabilities specified in Requirement R2 for redundant functionality at least once every 90 calendar days. If the test is unsuccessful, the Reliability Coordinator shall initiate action within two hours to restore redundant functionality. | |
| 01-Jan-19 | IRO-002-5 | R4. | Each Reliability Coordinator shall provide its System Operators with the authority to approve planned outages and maintenance of its telecommunication, monitoring and analysis capabilities. | |
| 01-Jan-19 | IRO-002-5 | R5. | Each Reliability Coordinator shall monitor Facilities, the status of Remedial Action Schemes, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordinator Area. | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Jan-19 | IRO-002-5 | R6. | Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant infrastructure. | |
| 01-Aug-14 | IRO-005-3.1a | R6 | The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes. | |
| 01-Aug-14 | IRO-005-3.1a | R7. | As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities. | |
| 15-Apr-13 | IRO-006-5 | R1. | Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-15 | IRO-006-WECC-2 | R1. | Each Reliability Coordinator shall approve or deny a request within five minutes of receiving the request for unscheduled flow transmission relief from the Transmission Operator of a Qualified Transfer Path that will result in the calculation of a Relief Requirement. | |
| 01-Oct-17 | IRO-008-2 | R1. | Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area. | |
| 01-Oct-17 | IRO-008-2 | R2. | Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential SOL and IROL exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. | |
| 01-Oct-17 | IRO-008-2 | R3. | Each Reliability Coordinator shall notify impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). | |
| 01-Oct-17 | IRO-008-2 | R4. | Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. | |
| 01-Oct-17 | IRO-008-2 | R5. | Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a SOL or IROL exceedance within its Wide Area. | |
| 01-Oct-17 | IRO-008-2 | R6. | Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the SOL or IROL exceedance identified in Requirement R5 has been prevented or mitigated. | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-17 | IRO-009-2 | R1. | For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding) | |
| 01-Oct-17 | IRO-009-2 | 1.1. | That can be implemented in time to prevent the identified IROL exceedance. | |
| 01-Oct-17 | IRO-009-2 | 1.2. | To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv. | |
| 01-Oct-17 | IRO-009-2 | R2. | Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. | |
| 01-Oct-17 | IRO-009-2 | R3. | Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. | |
| 01-Oct-17 | IRO-009-2 | R4. | Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities). | |
| 01-Apr-19 | IRO-010-2 | R1. | The Reliability Coordinator shall maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The data specification shall include but not be limited to: | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Apr-19 | IRO-010-2 | 1.1. | A list of data and information needed by the Reliability Coordinator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and external network data, as deemed necessary by the Reliability Coordinator. | |
| 01-Apr-19 | IRO-010-2 | 1.2. | Provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. | |
| 01-Apr-19 | IRO-010-2 | 1.3. | A periodicity for providing data. | |
| 01-Apr-19 | IRO-010-2 | 1.4. | The deadline by which the respondent is to provide the indicated data. | |
| 01-Apr-19 | IRO-010-2 | R2. | The Reliability Coordinator shall distribute its data specification to entities that have data required by the Reliability Coordinator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. | |
| 01-Apr-19 | IRO-010-2 | R3. | Each Reliability Coordinator, Balancing Authority, Generator Owner, Generator Operator, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications using: | Yes |
| 01-Apr-19 | IRO-010-2 | 3.1. | A mutually agreeable format. | Yes |
| 01-Apr-19 | IRO-010-2 | 3.2. | A mutually agreeable process for resolving data conflicts. | Yes |
| 01-Apr-19 | IRO-010-2 | 3.3. | A mutually agreeable security protocol. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-17 | IRO-014-3 | R1. | Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: | |
| 01-Oct-17 | IRO-014-3 | R1.1. | Criteria and processes for notifications | |
| 01-Oct-17 | IRO-014-3 | 1.2. | Energy and capacity shortages | |
| 01-Oct-17 | IRO-014-3 | 1.3. | Control of voltage, including the coordination of reactive resources | |
| 01-Oct-17 | IRO-014-3 | 1.4. | Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments | |
| 01-Oct-17 | IRO-014-3 | 1.5. | Provisions for periodic communications to support reliable operations | |
| 01-Oct-17 | IRO-014-3 | R2. | Each Reliability Coordinator shall maintain its Operating Procedures, Operating Processes, or Operating Plans identified in Requirement R1 as follows: | |
| 01-Oct-17 | IRO-014-3 | 2.1. | Review and update annually with no more than 15 months between reviews | |
| 01-Oct-17 | IRO-014-3 | 2.2. | Obtain written agreement from all of the Reliability Coordinators required to take the indicated action(s) for each update | |
| 01-Oct-17 | IRO-014-3 | 2.3. | Distribute to all Reliability Coordinators that are required to take the indicated action(s) within 30 days of an update | |
| 01-Oct-17 | IRO-014-3 | R3. | Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators. | |
| 01-Oct-17 | IRO-014-3 | R4. | Each impacted Reliability Coordinator shall operate as though the Emergency exists during each instance where Reliability Coordinators disagree on the existence of an Emergency. | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-17 | IRO-014-3 | R5. | Each Reliability Coordinator that Identifies an Emergency in its Reliability Coordinator Area shall develop an action plan to resolve the Emergency during those instances where impacted Reliability Coordinators disagree on the existence of an Emergency. | |
| 01-Oct-17 | IRO-014-3 | R6. | Each impacted Reliability Coordinator shall implement the action plan developed by the Reliability Coordinator that identifies the Emergency during those instances where Reliability Coordinators disagree on the existence of an Emergency, unless such actions would violate safety, equipment, regulatory, or statutory requirements. | |
| 01-Oct-17 | IRO-014-3 | R7. | Each Reliability Coordinator shall assist Reliability Coordinators, if requested and able, provided that the requesting Reliability Coordinator has implemented its emergency procedures, unless such actions cannot be physically implemented or would violate safety, equipment, regulatory, or statutory requirements. | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-18 | IRO-018-1 | R1. | Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time Assessments. The Operating Process or Operating Procedure shall include:<br>1.1. Criteria for evaluating the quality of Real-time data;<br>1.2. Provisions to indicate the quality of Real-time data to the System Operator; and<br>1.3. Actions to address Real-time data quality issues with the entity(ies) responsible for providing the data when data quality affects Real-time Assessments. | |
| 01-Oct-18 | IRO-018-1 | R2. | Each Reliability Coordinator shall implement an Operating Process or Operating Procedure to address the quality of analysis used in its Real-time Assessments. The Operating Process or Operating Procedure shall include: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]<br>2.1. Criteria for evaluating the quality of analysis used in its Real-time Assessments;<br>2.2. Provisions to indicate the quality of analysis used in its Real-time Assessments; and<br>2.3. Actions to address analysis quality issues affecting its Real-time Assessments. | |
| 01-Oct-18 | IRO-018-1 | R3. | Each Reliability Coordinator shall have an alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] | |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Jan-15 | PER-003-1 | 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:<br>1.1. Areas of Competency<br>1.1.1. Resource and demand balancing<br>1.1.2. Transmission operations<br>1.1.3. Emergency preparedness and operations<br>1.1.4. System operations<br>1.1.5. Protection and control<br>1.1.6. Voltage and reactive<br>1.1.7. Interchange scheduling and coordination<br>1.1.8. Interconnection reliability operations and coordination | |
| 15-Jan-13 | PER-004-2 | R1. | Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week. | |
| 15-Jan-13 | PER-004-2 | R2. | Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times. | |
| 01-Oct-16 | PER-005-2 | R1. | Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: [Please refer to the standard for more information] | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Oct-16 | PER-005-2 | R3. | Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 Part 1.1 or Requirement R2 Part 2.1. [Please refer to the standard for more information] | Yes |
| 01-Oct-16 | PER-005-2 | R4. | Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established IROLs, or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. [Please refer to the standard for more information] | Yes |
| 01-Oct-16 | PER-005-2 | R5. | Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 Part 1.1. [Please refer to the standard for more information] | Yes |
| 01-Apr-17 | PRC-002-2 | R5. | Each Responsible Entity shall: | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1. | Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1.1. | Generating resource(s) with: | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1.1.1. | Gross individual nameplate rating greater than or equal to 500 MVA. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 01-Apr-17 | PRC-002-2 | R5.1.1.2. | Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1.2. | Any one BES Element that is part of a stability (angular or voltage) related SOL. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1.3. | Each terminal of a high voltage direct current circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current portion of the converter. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1.4. | One or more BES Elements that are part of an IROL. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.1.5. | Any one BES Element within a major voltage sensitive area as defined by an area with an in-service under-voltage load shedding program. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.2. | Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least: | Yes |
| 01-Apr-17 | PRC-002-2 | R5.2.1. | One BES Element; and | Yes |
| 01-Apr-17 | PRC-002-2 | R5.2.2. | One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.3. | Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested. | Yes |
| 01-Apr-17 | PRC-002-2 | R5.4. | Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan. | Yes |
| 15-Apr-13 | TOP-006-2 | R2. | Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. | Yes |

| B.C. Effective Date | Standard Number | Requirement Number | Text of Requirement | Applicable to BA or TOP |
|---|---|---|---|---|
| 15-Apr-13 | TOP-006-2 | R3. | Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel | Yes |
| 15-Apr-13 | TOP-006-2 | R5. | Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. | Yes |
| 15-Apr-13 | TOP-006-2 | R7. | Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency. | Yes |
| 01-Nov-10 | TOP-007-0 | R1 | A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits. | Yes |

# BC Hydro MRS Reliability Coordinator

# Registration Filing

## Appendix C

## NERC Reliability Coordinator Standards of Conduct

# NERC Reliability Coordinator Standards of Conduct

## *Introduction*

An entity performing the functions of RELIABILITY COORDINATOR must treat all users of the interconnected transmission systems in a fair and non-discriminatory manner. A RELIABILITY COORDINATOR must conduct its affairs in conformance with the following standards:

**1. General rule**.

**1.1. Independence.** Except as provided in paragraph 1.2 of this section, the RELIABILITY COORDINATOR, its employees, or the employees of any of its affiliates who perform RELIABILITY COORDINATOR functions ("RELIABILITY COORDINATOR employees") must operate independently of employees/persons who engage in retail (energy purchases for or sales to native load customers) or wholesale (energy purchases or sales for resale) merchant functions ("Merchant employees"). [Note: "Operate independently" does not mean or require corporate separation of the RELIABILITY COORDINATOR from the Transmission Provider or Merchant employees or merchant functions.]

**1.2. Emergency actions.** Notwithstanding any other provision of these standards of conduct, in emergency circumstances that could jeopardize operational security, RELIABILITY COORDINATORS may take whatever steps are necessary to maintain system security.

**1.3. Reporting deviations from these Standards.** RELIABILITY COORDINATORS must report to NERC and the appropriate REGIONAL COUNCIL(S) the details of any deviation from these standards of conduct, within 24 hours of such deviation. NERC staff will post the reports to the NERC RELIABILITY COORDINATOR web site.

**2. Rules governing employee conduct**.

**2.1. Prohibitions**. RELIABILITY COORDINATOR employees are prohibited from:

**2.1.1. Merchant functions.** Conducting Merchant functions except as outlined in 1.2 above.

**2.1.2. Access to control facilities.** Allowing access for Merchant employees to the system control center or similar facilities used for RELIABILITY COORDINATOR functions that differs in any way from the access available to non-affiliated TRANSMISSION CUSTOMERS.

**2.1.3. Disclosing system information.** Disclosing to Merchant employees any information concerning the transmission system through non-public communications conducted off the OASIS, through access to information not posted on the OASIS that is not at the same time available to non-affiliated Transmission Customers without restriction, or through information on the OASIS that is not at the same time publicly available to all OASIS users (such as E-mail). If a RELIABILITY COORDINATOR employee discloses information in a manner contrary to the requirements of this subparagraph, the RELIABILITY COORDINATOR must, as soon as practicable, post such information on the NERC RELIABILITY COORDINATOR web site and inform the affected Transmission Provider to post such information on its OASIS.

**2.1.4. Sharing market information.** Sharing market information acquired from non-affiliated TRANSMISSION CUSTOMERS or potential non-affiliated Transmission

Customers, or developed in the course of performing RELIABILITY COORDINATOR functions, with any Merchant employees.

**2.2.** **Transfers**. RELIABILITY COORDINATOR employees or Merchant employees are not precluded from transferring between such functions as long as such transfer is not used as a means to circumvent these standards of conduct. Notices of any employee transfer to or from RELIABILITY COORDINATOR functions must be reported to NERC and the appropriate REGIONAL COUNCIL(S). NERC staff will post the reports to the NERC RELIABILITY COORDINATOR web site. The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e., on behalf of the RELIABILITY COORDINATOR, merchant or transmission provider, or merchant or transmission affiliate), and the effective date of the transfer. The information posted under this section must remain on the NERC web site for 90 days.

**2.3.** **Books and records**.

**2.3.1.** **Available for audit.** A RELIABILITY COORDINATOR must keep sufficient records of its activities available for audit.

**2.3.2.** **Separate records.** A RELIABILITY COORDINATOR must maintain its records separately from those of any affiliates and these must be available for inspection by NERC and the appropriate Regional Council(s).

**3.** **Rules governing maintenance of written procedures.**

**3.1.** **Publicly available.** A RELIABILITY COORDINATOR must provide an explanation for posting on the NERC RELIABILITY COORDINATOR web site describing the implementation of these standards of conduct in sufficient detail to demonstrate that the RELIABILITY COORDINATOR employees operate independently from merchant employees and that it is otherwise in compliance with these requirements.

**3.2.** **Provided to all employees.** A copy of the signed Standards of Conduct document shall be given to all employees with RELIABILITY COORDINATOR responsibilities.

**AGREEMENT**

As part of the process of being designated a NERC RELIABILITY COORDINATOR, [*Name of Organization*] hereby agrees to abide by the terms of the foregoing NERC Reliability Coordinator Standards of Conduct.

[*Name of Organization*]

By: ______________________________________________

Title: ______________________________________________

Date: ______________________________________________

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

By: ______________________________________________

Title: ______________________________________________

Date: ______________________________________________