# NORMES DE FIABILITÉ DE LA NERC

# (VERSION ANGLAISE)

## A. Introduction

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

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

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

4. **Applicability:**

   **4.1.** Transmission Operators.

   **4.2.** Balancing Authorities.

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

## B. Requirements

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

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

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

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

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

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

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

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

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

## C. Measures

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

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

## D. Compliance

### 1. Compliance Monitoring Process

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

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

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

**1.3. Additional Reporting Requirement**

No additional reporting required.

**1.4. Data Retention**

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

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

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

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

**1.5. Additional Compliance Information**
None

## 2. Violation Severity Levels

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

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

E. **Regional Differences**

None identified.

**Version History**

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

## Appendix QC-EOP-003-2
## Provisions specific to the standard EOP-003-2 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Load shedding Plans**
2. **Number:** EOP-003-2
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
   - **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016
   - **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016
   - **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements

No specific provision

## C. Measures

No specific provision

## D. Compliance

1. **Compliance Monitoring Process**

   **1.1. Compliance Monitoring Responsibility**

   The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

   **1.2. Compliance Monitoring**

   No specific provision

   **1.3. Additional Reporting Requirement**

   No specific provision

   **1.4. Data Retention**

   No specific provision

   **1.5. Additional Compliance Information**

   No specific provision

2. **Violation Severity Levels**

   No specific provision

**Appendix QC-EOP-003-2**
**Provisions specific to the standard EOP-003-2 applicable in Québec**

## E. Regional Differences

No specific provision

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |

## A. Introduction

1. **Title: Geomagnetic Disturbance Operations**
2. **Number:** EOP-010-1
3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.
4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1** Reliability Coordinator

   **4.1.2** Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV

5. **Background:**

   Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Protection System Misoperation, the combination of which may result in voltage collapse and blackout.

6. **Effective Date:**

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

## B. Requirements and Measures

**R1.** Each Reliability Coordinator shall develop, maintain, and implement a 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: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]*

**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.

**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.

**M1**. Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.

**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. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*

**M2.** Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.

**R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*

**3.1**. Steps or tasks to receive space weather information.

**3.2**. System Operator actions to be initiated based on predetermined conditions.

**3.3**. The conditions for terminating the Operating Procedure or Operating Process.

**M3**. Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

## C. Compliance

**1. Compliance Monitoring Process**

**1.1. Compliance Enforcement Authority**

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

**1.2. Evidence Retention**

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

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

The responsible entities shall retain documentation as evidence for three years.

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

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaint

**1.4. Additional Compliance Information**

None

## Table of Compliance Elements

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| R1 | Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations | Medium | The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it. | N/A | The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2. | The Reliability Coordinator did not have a GMD Operating Plan<br>OR<br>The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area. |
| R2 | Same-day Operations, Real-time Operations | Medium | N/A | N/A | N/A | The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. |
| R3 | Long-term Planning, Operations Planning, | Medium | The Transmission Operator had a GMD Operating Procedure or Operating Process, | The Transmission Operator's GMD Operating Procedure or Operating Process | The Transmission Operator's GMD Operating Procedure or Operating Process | The Transmission Operator did not have a GMD Operating Procedure or Operating |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Same-day Operations, Real-time Operations | | but failed to maintain it. | failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3. | failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3. | Process<br><br>OR<br><br>The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process. |

## D. Regional Variances

None.

## E. Interpretations

None.

## F. Guideline and Technical Basis

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

**Rationale for R1:**

An Operating Plan is implemented by carrying out its stated actions.

Coordination is intended to ensure that Operating Procedures are not in conflict with one another. An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Elements of Requirement R1 take place in various time horizons. Development of the GMD Operating Plan occurs in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan occurs in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan occurs in the Operations Planning, Same-Day and Real-Time Time Horizons.

**Rationale for R2:**

Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

**Rationale for R3:**

In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | 11/07/2013 | Adopted by the NERC Board of Trustees | |
| 1 | 6/19/2014 | FERC Order issued approving EOP-010-1 | |

## Appendix QC-EOP-010-1
## Provisions specific to the standard EOP-010-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Geomagnetic Disturbance Operation**
2. **Number:** EOP-010-1
3. **Purpose:** No specific provision
4. **Applicability:**

   No specific provisions
5. **Background:**

   No specific provisions
6. **Effective Date:**

   **6.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016

   **6.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016

   **6.3.** Effective date of the standard and its appendix in Québec:

| Requirement | Effective date in Québec |
|---|---|
| R1, R3 | January 1, 2017 |
| R2 | No effective date |

## B. Requirements and Measures

No specific provision

## C. Compliance

1. **Compliance Monitoring Process**

   **1.1. Compliance Enforcement Authority**

   The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

   **1.2. Evidence Retention**

   No specific provision

   **1.3. Compliance Monitoring and Assessment Processes**

   No specific provision

   **1.4. Additional Compliance Information**

   No specific provisions

**Table of Compliance Elements**

No specific provision

## D. Regional Differences

No specific provision

## E. Interpretation

No specific provision

## F. Guideline and Technical Basis

No specific provisions

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New Appendix | New |
| | | | |

## A. Introduction

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

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

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

4. **Applicability**

   **4.1.** Reliability Coordinator.

5. **Proposed Effective Date:**

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

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

## B. Requirements

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

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

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

## C. Measures

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

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

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

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

For Reliability Coordinators that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

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

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

#### 1.4. Data Retention

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

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

The Reliability Coordinator shall retain evidence for Requirement R1, Measure M1 and Requirement R2, Measure M2 for a rolling 30 days. The Reliability Coordinator shall keep evidence for Requirement R3, Measure M3 for a rolling three months.

#### 1.5. Additional Compliance Information

None.

## 2. Violation Severity Levels

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

## E. Regional Variances

None

## F. Associated Documents

None

### Version History

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

## Appendix QC-IRO-008-1
## Provisions specific to the standard IRO-008-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

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

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

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

4. **Applicability:**

   **Functions**

   No specific provision

   **Facilities**

   No specific provision

5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements

No specific provision

## C. Measures

No specific provision

## D. Compliance

1. **Compliance Monitoring Process**

   **1.1. Compliance Enforcement Authority**

   The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

   **1.2. Compliance Monitoring Period and Reset Time Frame**

   No specific provision

   **1.3. Compliance Monitoring and Enforcement Processes**

   No specific provision

   **1.4. Data Retention**

   No specific provision

**1.5. Additional Compliance Information**

No specific provision

**2. Violation Severity Levels**

No specific provision

## E. Regional Differences

No specific provision

## F. Associated Documents

No specific provision

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |

## A. Introduction

1. **Title:** **Reliability Coordinator Actions to Operate Within IROLs**

2. **Number:** IRO-009-1

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate instances of exceeding Interconnection Reliability Operating Limits (IROLs).

4. **Applicability:**

   **4.1.** Reliability Coordinator.

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

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

## B. Requirements

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

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

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

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

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

## C. Measures

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

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

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

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

For Reliability Coordinators that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

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

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Exception Reporting

**1.4. Data Retention**

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

The Reliability Coordinator shall retain evidence of Requirement R1, Requirement R2, and Measure M1, for a rolling 12 months.

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

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

**1.5. Additional Compliance Information**

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

## 2. Violation Severity Levels

| Requirement | Lower | Moderate | High | Severe |
|---|---|---|---|---|
| **R1** | | | | An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to prevent exceeding that IROL. (R1) |
| **R2** | | | | An IROL in its Reliability Coordinator Area was identified one or more days in advance and the Reliability Coordinator does not have an Operating Process, Procedure, or Plan that identifies actions to mitigate exceeding that IROL within the IROL's $T_v$. (R2) |
| **R3** | | | | An assessment of actual or expected system conditions predicted that an IROL in the Reliability Coordinator's Area would be exceeded, but no Operating Processes, Procedures, or Plans were implemented. (R3) |
| **R4** | | | Actual system conditions | Actual system conditions |

| Requirement | Lower | Moderate | High | Severe |
| --- | --- | --- | --- | --- |
| | | | showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and there was a delay of five minutes or more before acting or directing others to act to mitigate the magnitude and duration of the instance of exceeding that IROL, however the IROL was mitigated within the IROL $T_v$. (R4) | showed that there was an instance of exceeding an IROL in its Reliability Coordinator Area, and that IROL was not resolved within the IROL's $T_v$. (R4) |
| **R5** | Not applicable. | Not applicable. | Not applicable. | There was a disagreement on the value of the IROL or its $T_v$ and the most conservative limit under consideration was not used. (R5) |

## E. Regional Variances

None

## F. Associated Documents

IROL Violation Report

### Version History

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

## Appendix QC-IRO-009-1
## Provisions specific to the standard IRO-001-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Reliability Coordinator Actions to Operate Within IROLs**
2. **Number:** IRO-009-1
3. **Purpose:** No specific provision
4. **Applicability:**

   **Functions**

   No specific provision

   **Facilities**

   No specific provision

5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements

No specific provision

## C. Measures

No specific provision

## D. Compliance

1. **Compliance Monitoring Process**

   **1.1. Compliance Enforcement Authority**

   The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

   **1.2. Compliance Monitoring Period and Reset Time Frame**

   No specific provision

   **1.3. Compliance Monitoring and Enforcement Processes**

   No specific provision

   **1.4. Data Retention**

   No specific provision

   **1.5. Additional Compliance Information**

   No specific provision

**2. Violation Severity Levels**

No specific provision

## E. Regional Variances

No specific provision

## F. Associated Documents

No specific provision

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |
| | | | |

## A. Introduction

1. **Title:** **Reliability Coordinator Data Specification and Collection**

2. **Number:** IRO-010-1a

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring the Reliability Coordinator has the data it needs to monitor and assess the operation of its Reliability Coordinator Area.

4. **Applicability**

   **4.1.** Reliability Coordinator.

   **4.2.** Balancing Authority.

   **4.3.** Generator Owner.

   **4.4.** Generator Operator.

   **4.5.** Interchange Authority.

   **4.6.** Load-Serving Entity.

   **4.7.** Transmission Operator.

   **4.8.** Transmission Owner.

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

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

## B. Requirements

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

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

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

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

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

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

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

## C. Measures

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

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

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

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

For Reliability Coordinators and other functional entities that work for the Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

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

#### 1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

#### 1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

**1.4.Data Retention**

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

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

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

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

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

**1.5. Additional Compliance Information**

**1.5.1** None.

## 2. Violation Severity Levels

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

## E. Regional Variances

None

## F. Associated Documents

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

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | October 17, 2008 | Adopted by Board of Trustees | New |
| 1a | August 5, 2009 | Added Appendix 1: Interpretation of R1.2 and R3 as approved by Board of Trustees | Addition |
| 1a | March 17, 2011 | Order issued by FERC approving IRO-010-1a (approval effective 5/23/11) | |

## Appendix 1

## Interpretation of Requirements R1.2 and R3

Text of Requirements R1.2 and R3

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

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

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

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

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

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

*Question 1*

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

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

*Question 2*

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

**Response: The intent of Requirement R3 is for each responsible entity to ensure that its data and information (as stated in the documented specification in Requirement R1) are provided to the Reliability Coordinator.**

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

*Question 3*

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

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

## Appendix QC-IRO-010-1a
## Provisions specific to the standard IRO-010-1a applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Reliability Coordinator Data Specification and Collection**
2. **Number:** IRO-010-1a
3. **Purpose:** No specific provision
4. **Applicability:**

   **Functions**

   No specific provision

   **Facilities**

   This standard only applies to the facilities of the Main Transmission System (RTP).
5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements

**Specific provision regarding generation facilities for industrial use applicable to requirement R3:**

The Generator Operator whose facilities are mainly used to supply industrial loads is not required to communicate data to the reliability coordinator, other than data related to :
(i) in the planning time horizon, the net power at the connection points of its system, total production of its generation facilities and its system load and
(ii) in real time, the net power at the connection points of its system.

## C. Measures

No specific provision

## D. Compliance

1. **Compliance Monitoring Process**

   **1.1. Compliance Enforcement Authority**

   The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

   **1.2. Compliance Monitoring Period and Reset Time Frame**

   No specific provision

   **1.3. Compliance Monitoring and Enforcement Processes**

   No specific provision

**1.4. Data Retention**

No specific provision

**1.5. Additional Compliance Information**

No specific provision

**2. Violation Severity Levels**

No specific provision

## E. Regional Differences

No specific provision

## F. Associated Documents

**Annexe 1**

No specific provision

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |

## A. Introduction

1. **Title:** **Coordination of Real-time Activities Between Reliability Coordinators**

2. **Number:** **IRO-016-1**

3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.

4. **Applicability**

   **4.1.** Reliability Coordinator

5. **Effective Date:** November 1, 2006

## B. Requirements

**R1.** The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.

**R1.1.** If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.

**R1.2.** If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).

**R1.2.1.** If time permits, this re-evaluation shall be done before taking corrective actions.

**R1.2.2.** If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.

**R1.3.** If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.

**R2.** The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.
(Retirement approved by FERC effective January 21, 2014.)

## C. Measures

**M1.** For each event that requires Reliability Coordinator-to-Reliability Coordinator coordination, each involved Reliability Coordinator shall have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

## D. Compliance

1. **Compliance Monitoring Process**

**1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization

**1.2. Compliance Monitoring Period and Reset Time Frame**

The performance reset period shall be one calendar year.

**1.3. Data Retention**

The Reliability Coordinator shall keep auditable evidence for a rolling 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until it has been found compliant. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

**1.4. Additional Compliance Information**

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall use a scheduled on-site review at least once every three years. The Compliance Monitor shall conduct an investigation upon a complaint that is received within 30 days of an alleged infraction's discovery date. The Compliance Monitor shall complete the investigation and report back to all involved Reliability Coordinators (the Reliability Coordinator that complained as well as the Reliability Coordinator that was investigated) within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been coordinating actions to prevent or resolve potential, expected, or actual problems that adversely impact the Interconnection.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five working days of a request as part of an investigation upon complaint:

**1.4.1** Evidence (operator log or other data source) to show coordination with other Reliability Coordinators.

**2. Levels of Non-Compliance**

**2.1. Level 1:** For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.

**2.2. Level 2:** Not applicable.

**2.3. Level 3:** Not applicable.

**2.4. Level 4:** For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did not coordinate with other Reliability Coordinators.

## E. Regional Differences

None identified.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | August 10, 2005 | 1. Changed incorrect use of certain hyphens (-) to "en dash (–)."<br>2. Hyphenated "30-day" and "Reliability Coordinator-to-Reliability Coordinator" when used as adjective. | 01/20/06 |

| | | | |
|---|---|---|---|
| | | 3. Changed standard header to be consistent with standard “Title.”<br>4. Added “periods” to items where appropriate.<br>5. Initial capped heading “Definitions of Terms Used in Standard.”<br>6. Changed “Timeframe” to “Time Frame” in item D, 1.2.<br>7. Lower cased all words that are not “defined” terms — drafting team, and self-certification.<br>8. Changed apostrophes to “smart” symbols.<br>9. Removed comma after word “condition” in item R.1.1.<br>10. Added comma after word “expected” in item 1.4, last sentence.<br>11. Removed extra spaces between words where appropriate. | |
| 1 | February 7, 2006 | Adopted by NERC Board of Trustees | |
| 1 | March 16, 2007 | Approved by FERC | |
| 1 | February 7, 2013 | R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. | |
| 1 | November 21, 2013 | R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) | |

## Appendix QC-IRO-016-1
## Provisions specific to the standard IRO-016-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Coordination of Real-time Activities Between Reliability Coordinators**
2. **Number:** IRO-016-1
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
   - **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016
   - **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016
   - **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements

No specific provision

## C. Measures

No specific provision

## D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**

     The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.
   - **1.2. Compliance Monitoring Period and Reset Time Frame**

     No specific provision
   - **1.3. Data Retention**

     No specific provision
   - **1.4. Additional Compliance Information**

     No specific provision
2. **Levels of Non-Compliance**

   No specific provision

## E. Regional Differences

No specific provision

**Appendix QC-IRO-016-1**
**Provisions specific to the standard IRO-016-1 applicable in Québec**

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | October 30, 2013 | New appendix | New |
| 1 | September 30, 2016 | • Modification of adoption dates<br>• Retirement of requirement R2 in the standard | |

## A. Introduction

1. **Title:** **Protection System Maintenance**
2. **Number:** PRC-005-2
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1** Transmission Owner

   **4.1.2** Generator Owner

   **4.1.3** Distribution Provider

   **4.2. Facilities:**

   **4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   **4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   **4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   **4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.

   **4.2.5** Protection Systems for generator Facilities that are part of the BES, including:

   **4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

   **4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.

   **4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

   **4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

5. **Effective Date:** See Implementation Plan

## B. Requirements

**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

**1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

> ***Component Type*** *- Any one of the five specific elements of the Protection System definition.*

**1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.

> **Component** – *A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.*

**R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

> ***Unresolved Maintenance Issue*** *- A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.*

**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

## C. Measures

**M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)

**M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.

**M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

**M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

**M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

Regional Entity

#### 1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

### 1.3. Evidence Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

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

### 1.4. Additional Compliance Information

None.

## 2. Violation Severity Levels

| Requirement Number | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1 | The responsible entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1) | The responsible entity's PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2). | The responsible entity failed to establish a PSMP.<br>OR<br>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).<br>OR<br>The responsible entity's PSMP failed to include applicable station batteries in a time-based program. (Part 1.1) |
| R2 | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years. | NA | The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years. | The responsible entity uses performance-based maintenance intervals in its PSMP but:<br>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP<br>OR<br>2) Failed to reduce Countable Events to no more than 4% within five years<br>OR<br>3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to: |

| Requirement Number | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | • Annually update the list of Components,<br>OR<br>• Annually perform maintenance on the greater of 5% of the segment population or 3 Components,<br>OR<br>• Annually analyze the program activities and results for each Segment. |
| R3 | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. | For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. |
| R4 | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP. | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP. | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP. | For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP. |

| Requirement Number | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R5 | The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues. | The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

## E. Regional Variances

None

## F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

### Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| 1 | December 1, 2005 | 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).”<br>2. Added “periods” to items where appropriate.<br>3. Changed “Timeframe” to “Time Frame” in item D, 1.2. | 01/20/05 |
| 1a | February 17, 2011 | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers | Project 2009-17 interpretation |
| 1a | February 17, 2011 | Adopted by Board of Trustees | |
| 1a | September 26, 2011 | FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011) | |
| 1.1a | February 1, 2012 | Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility | Revision under Project 2010-07 |
| 1b | February 3, 2012 | FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b. | Project 2009-10 Interpretation |
| 1.1b | April 23, 2012 | Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b. | Revision under Project 2010-07 |

| | | | |
|---|---|---|---|
| 1.1b | May 9, 2012 | PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO). | |
| 2 | November 7, 2012 | Adopted by Board of Trustees | Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2 | October 17, 2013 | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section. | |
| 2 | December 19, 2013 | FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014. | |
| 2 | May 7, 2014 | Adopted by the NERC Board of Trustees to modify VSLs for Requirement R1. | |
| 2 | August 25, 2014 | FERC issued letter order to modify VSLs for Requirement R1. | |

<table>
<tr><th colspan="3">Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3)</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval[1]</th><th>Maintenance Activities</th></tr>
<tr><td>Any unmonitored protective relay not having all the monitoring attributes of a category below.</td><td>6 calendar years</td><td>For all unmonitored relays:<br>• Verify that settings are as specified<br>For non-microprocessor relays:<br>• Test and, if necessary calibrate<br>For microprocessor relays:<br>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.<br>• Verify acceptable measurement of power system input values.</td></tr>
<tr><td>Monitored microprocessor protective relay with the following:<br>• Internal self-diagnosis and alarming (see Table 2).<br>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.<br>• Alarming for power supply failure (see Table 2).</td><td>12 calendar years</td><td>Verify:<br>• Settings are as specified.<br>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.<br>• Acceptable measurement of power system input values.</td></tr>
</table>

[1] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relay<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval**[1] | **Maintenance Activities** |
| Monitored microprocessor protective relay with preceding row attributes and the following:<br>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).<br>• Alarming for change of settings (See Table 2). | 12 calendar years | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below. | 4 calendar months | Verify that the communications system is functional. |
| | 6 calendar years | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2). | 12 calendar years | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with all of the following:<br>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2)<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). | 12 calendar years | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any voltage and current sensing devices not having monitoring attributes of the category below. | 12 calendar years | Verify that current and voltage signal values are provided to the protective relays. |
| Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None. |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Protection System Station dc supply using **Vented Lead-Acid (VLA) batteries** not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage<br>Inspect:<br>• Electrolyte level<br>• For unintentional grounds |
| | 18 Calendar Months | Verify:<br>• Float voltage of battery charger<br>• Battery continuity<br>• Battery terminal connection resistance<br>• Battery intercell or unit-to-unit connection resistance<br>Inspect:<br>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible<br>• Physical condition of battery rack |
| | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Protection System Station dc supply **with Valve Regulated Lead-Acid (VRLA) batteries** not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage<br>Inspect:<br>• For unintentional grounds |
| | 6 Calendar Months | Inspect:<br>• Condition of all individual units by measuring battery cell/unit internal ohmic values. |
| | 18 Calendar Months | Verify:<br>• Float voltage of battery charger<br>• Battery continuity<br>• Battery terminal connection resistance<br>• Battery intercell or unit-to-unit connection resistance<br>Inspect:<br>• Physical condition of battery rack |
| | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

<table>
<tr><th colspan="3">Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:<ul><li>Station dc supply voltage</li></ul>Inspect:<ul><li>Electrolyte level</li><li>For unintentional grounds</li></ul></td></tr>
<tr><td>18 Calendar Months</td><td>Verify:<ul><li>Float voltage of battery charger</li><li>Battery continuity</li><li>Battery terminal connection resistance</li><li>Battery intercell or unit-to-unit connection resistance</li></ul>Inspect:<ul><li>Cell condition of all individual battery cells.</li><li>Physical condition of battery rack</li></ul></td></tr>
<tr><td>6 Calendar Years</td><td>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.</td></tr>
</table>

| Table 1-4(d)<br>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage<br>Inspect:<br>• For unintentional grounds |
| | 18 Calendar Months | Inspect:<br>Condition of non-battery based dc supply |
| | 6 Calendar Years | Verify that the dc supply can perform as manufactured when ac power is not present. |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPS, non-distributed UFLS, and non-distributed UVLS systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2). | No periodic maintenance specified | No periodic verification of station dc supply voltage is required. |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2). | | No periodic inspection of the electrolyte level for each cell is required. |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2). | | No periodic inspection of unintentional dc grounds is required. |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2). | | No periodic verification of float voltage of battery charger is required. |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2). | | No periodic verification of the battery continuity is required. |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2). | | No periodic verification of the intercell and terminal connection resistance is required. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2). | | No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured. |
| Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2). | | No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required. |

| Table 1-5<br>Component Type - Control Circuitry Associated With Protective Functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br>**Note:** Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry). | 6 calendar years | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device. |
| Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry). | 6 calendar years | Verify electrical operation of electromechanical lockout devices. |
| Unmonitored control circuitry associated with SPS. | 12 calendar years | Verify all paths of the control circuits essential for proper operation of the SPS. |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays. | 12 calendar years | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or SPS whose integrity is monitored and alarmed (See Table 2). | No periodic maintenance specified | None. |

| **Table 2 – Alarming Paths and Monitoring**<br>In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated. | No periodic maintenance specified | None. |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any unmonitored protective relay not having all the monitoring attributes of a category below. | 6 calendar years | Verify that settings are as specified<br>For non-microprocessor relays:<br>• Test and, if necessary calibrate<br>For microprocessor relays:<br>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.<br>• Verify acceptable measurement of power system input values. |
| Monitored microprocessor protective relay with the following:<br>• Internal self diagnosis and alarming (See Table 2).<br>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.<br>Alarming for power supply failure (See Table 2). | 12 calendar years | Verify:<br>• Settings are as specified.<br>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.<br>• Acceptable measurement of power system input values |
| Monitored microprocessor protective relay with preceding row attributes and the following:<br>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).<br>Alarming for change of settings (See Table 2). | 12 calendar years | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems. | 12 calendar years | Verify that current and/or voltage signal values are provided to the protective relays. |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system. | 12 calendar years | Verify Protection System dc supply voltage. |
| Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils). | 12 calendar years | Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils). | 12 calendar years | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices. |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified | None. |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems. | No periodic maintenance specified | None. |

## PRC-005 — Attachment A

### Criteria for a Performance-Based Protection System Maintenance Program

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

> **Segment** – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

> **Countable Event** – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## Appendix QC-PRC-005-2
## Provisions specific to the standard PRC-005-2 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Protection System Maintenance**

2. **Number:** PRC-005-2

3. **Purpose:** No specific provision

4. **Applicability:**

   **4.1. Functional Entities**

   No specific provision

   **4.2. Facilities**

   **4.2.1.** Protection Systems that are installed for the purpose of detecting Faults on Bulk Power System (BPS) Elements (lines, busses, transformers, etc.).

   **4.2.2.** Protection Systems used for underfrequency load-shedding systems.

   **4.2.3.** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BPS reliability.

   **4.2.4.** Protection System installed as a Special Protection System (SPS) for BPS reliability. Special Protection System are those classified type I or II by NPCC.

   **4.2.5.** Protection Systems for generator Facilities that are part of the BPS, including :

   **4.2.5.1.** No specific provision

   **4.2.5.2.** Protection Systems for generator step-up transformers for generators that are part of BPS.

   **4.2.5.3.** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BPS (e.g., transformers connecting facilities such as wind-farms to the BPS).

   **4.2.5.4.** Protection Systems for station service or excitation transformers connected to the generator bus of generator which are part of the BPS, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l’énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l’énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec:

| Requirements | Effective date in Québec |
|---|---|
| R1, R2 and R5 | January 1, 2017 |
| R3 and R4 | See the table below |

| Maximum Maintenance Interval (Tables 1 to 3) | Maintenance Required (%) | Implementation Date in Québec |
|---|---|---|
| 1 year | 100% | January 1, 2017 |
| 1 year to 2 years | 100% | April 1, 2017 |
| 3 years | 30% | April 1, 2017 |
| | 60% | April 1, 2017 |
| | 100% | April 1, 2018 |
| 6 years | 30% | April 1, 2017 |
| | 60% | April 1, 2019 |
| | 100% | April 1, 2021 |
| 12 years | 30% | April 1, 2019 |
| | 60% | April 1, 2023 |
| | 100% | April 1, 2027 |

## B. Requirements

No specific provision

## C. Measures

No specific provision

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

The Régie de l’énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

#### 1.2. Compliance Monitoring and Enforcement Processes

No specific provision

#### 1.3. Evidence Retention

No specific provision

### 1.4. Additional Compliance Information

No specific provision

### 2. Violation Severity Levels

No specific provision

## E. Regional Differences

No specific provision

## F. Supplemental Reference Document

No specific provision

### Table 1-1 to Table 1-5

Replace all occurrences of the expression “Non-BES” with the expression “Non-BPS”

### Table 2

No specific provision

### Table 3

Replace all occurrences of the expression “Non-BES” with the expression “Non-BPS”

### Attachment A

No specific provision

### Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |

## A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
2. **Number:** PRC-019-1
3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.
4. **Applicability:**

**4.1. Functional Entities**

**4.1.1** Generator Owner

**4.1.2** Transmission Owner that owns synchronous condenser(s)

**4.2. Facilities**

For the purpose of this standard, the term, "applicable Facility" shall mean any one of the following:

**4.2.1** Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

**4.2.2** Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

**4.2.3** Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

**4.2.4** Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator's restoration plan.

5. **Effective Date:**

**5.1.** In those jurisdictions where regulatory approval is required:

**5.1.1** By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

**5.1.2** By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each

Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

**5.1.4** By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

**5.2.** In those jurisdictions where regulatory approval is not required:

**5.2.1** By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

**5.2.2** By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

**5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

**5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

## B. Requirements

**R1.** At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[1] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**1.1.** Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

[1] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

**1.1.1.** The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

**1.1.2.** The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

**R2.** Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

## C. Measures

**M1.** Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[2] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

**M2.** Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional entity approved by FERC or other applicable governmental authority shall serve as the CEA.

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

### 1.2. Evidence Retention

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

The Generator Owner and Transmission Owner shall retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

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

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

### 1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

### 1.4. Additional Compliance Information

None

## 2. Violation Severity Levels

| R # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **R1** | The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar | The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar | The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar | The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar |

| | | | | |
|---|---|---|---|---|
| | years but less than or equal to 5 calendar years plus 4 months after the previous coordination. | years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination. | years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination. | years plus 12 months after the previous coordination. |
| **R2** | The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. | The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. | The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. | The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination. |

## E. Regional Variances

None.

## F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,”Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

“IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above”

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | February 7, 2013 | Adopted by NERC Board of Trustees | New |
| 1 | March 20, 2014 | FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.) | |

## G. Reference

### Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

**NOTE:** This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using $X_d$ as the direct axis saturated synchronous reactance of the generator, $X_s$ as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer and $V_g$ as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$C = V^2_g/2*(1/X_s-1/X_d)$

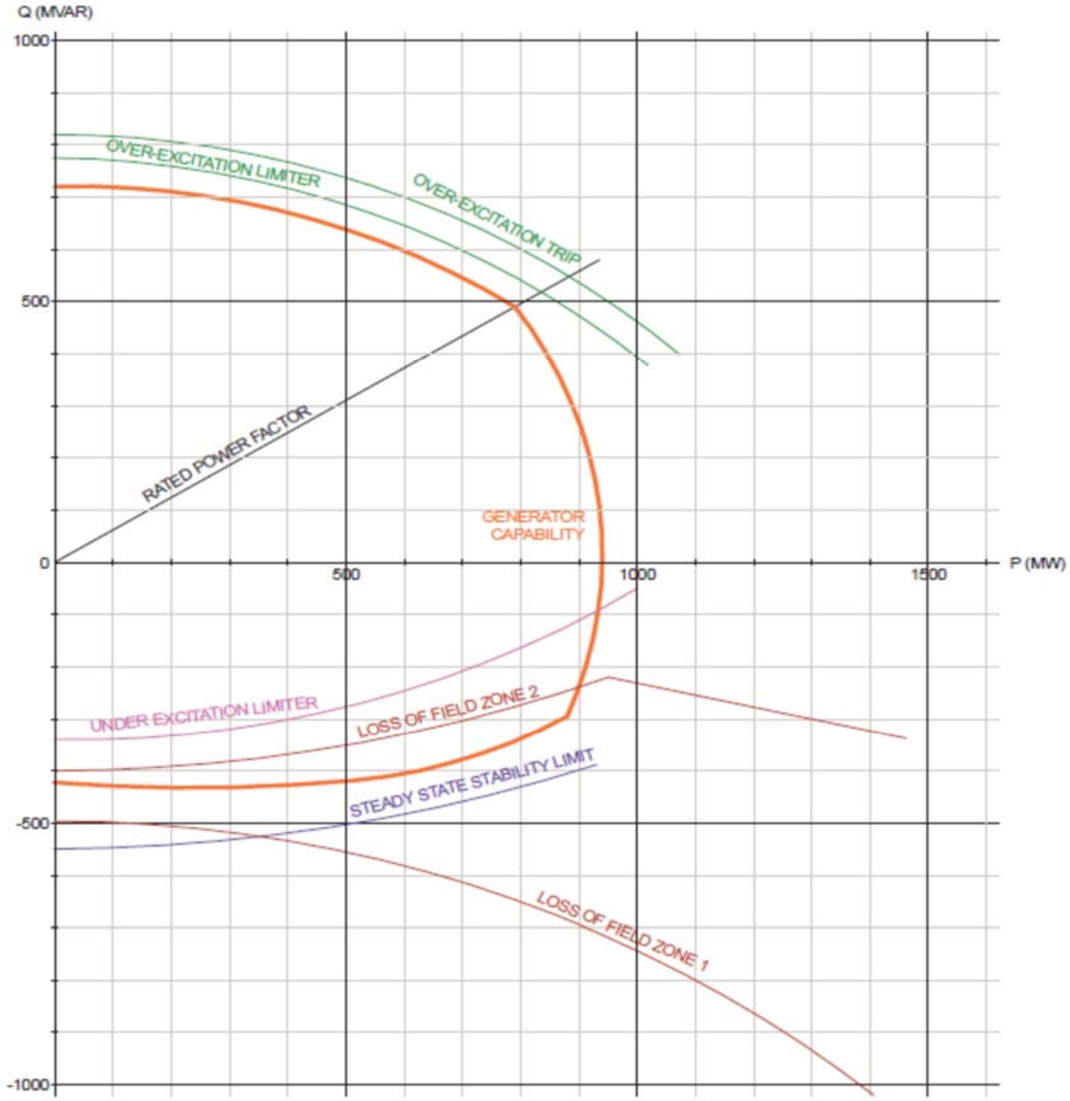
$R = V^2_g/2*(1/X_s+1/X_d)$

On an R-X diagram using $X_d$ as the direct axis saturated synchronous reactance of the generator, and $X_s$ as the equivalent reactance between the generator terminals and the "infinite bus" including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

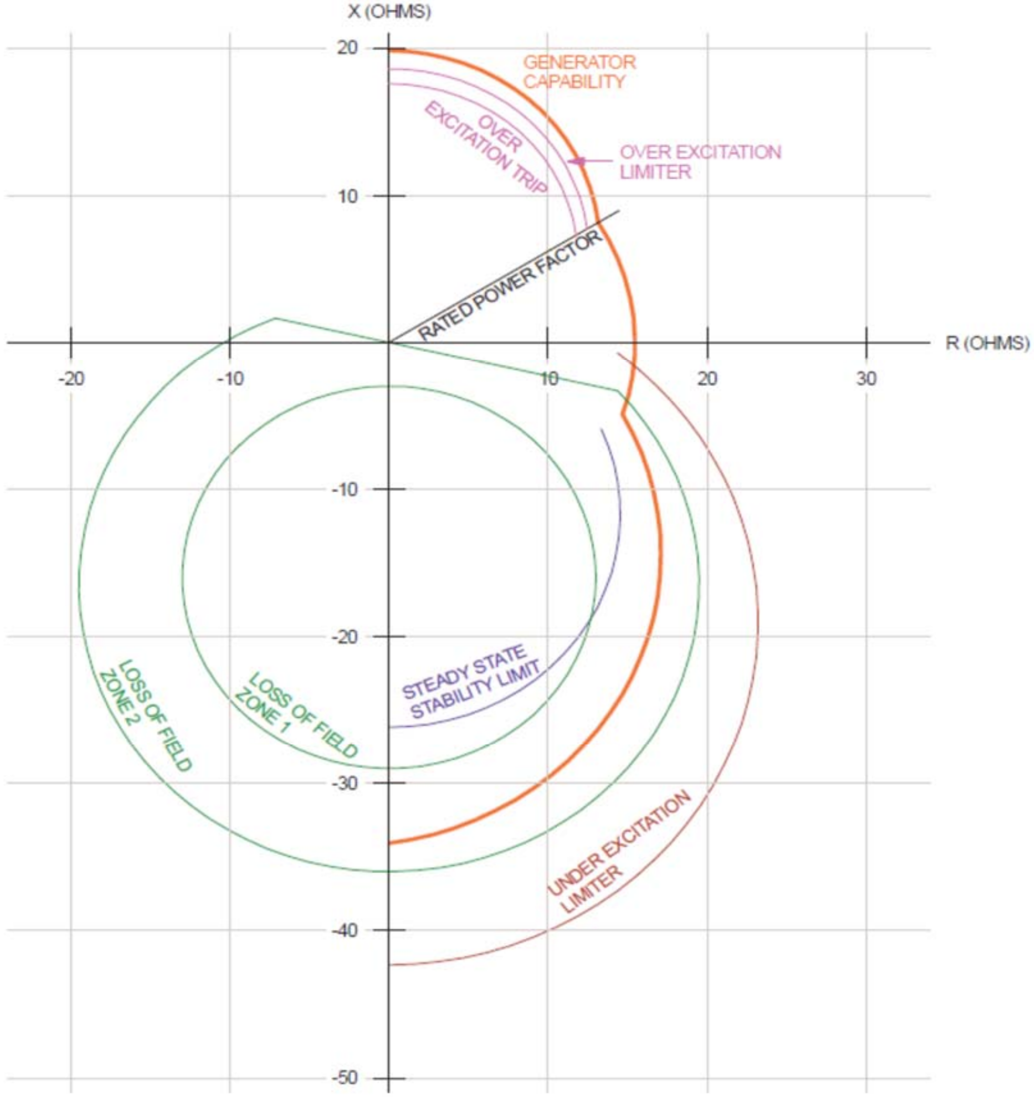
$C = (X_d-X_s)/2$

$R = (X_d+X_s)/2$

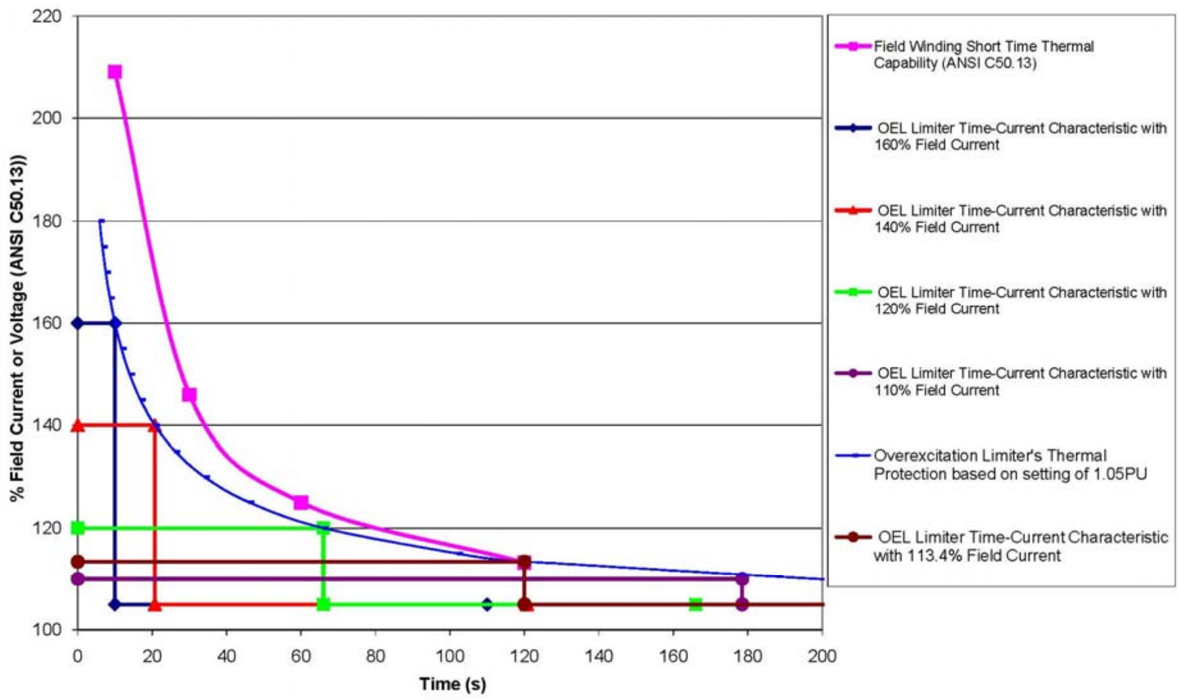
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



## Appendix QC-PRC-019-1
## Provisions specific to the standard PRC-019-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** **Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection**

2. **Number:** PRC-019-1

3. **Purpose:** No specific provision

4. **Applicability:**

   **4.1. Functional Entities**

   No specific provision

   **4.2. Facilities**

   **4.2.1** Generating unit that is part of the Main Transmission System (RTP).

   **4.2.2** Synchronous condenser that is part of the Main Transmission System (RTP).

   **4.2.3** Generating plant/Facility that is part of the Main Transmission System (RTP).

   **4.2.4** No specific provision

5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l’énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l’énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec:

| Effective date in Québec | Applicable facilities connected to the RTP (all requirements) (%) | Applicable facilities not connected to the RTP (all requirements) (%) |
|---|---|---|
| October 1, 2017 | At least 40% of applicable facilities | At least 15% of applicable facilities |
| October 1, 2018 | At least 60% of applicable facilities | At least 50% of applicable facilities |
| October 1, 2019 | At least 80% of applicable facilities | At least 75% of applicable facilities |
| October 1, 2020 | 100% of applicable facilities | 100% of applicable facilities |

## B. Requirements

No specific provision

## C. Measures

No specific provision

**Appendix QC-PRC-019-1**
**Provisions specific to the standard PRC-019-1 applicable in Québec**

## D. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

#### 1.2. Evidence Retention

No specific provision

#### 1.3. Compliance Monitoring and Enforcement Processes:

No specific provision

#### 1.4. Additional Compliance Information

No specific provision

### 2. Violation Severity Levels

No specific provision

## E. Regional Differences

No specific provision

## F. Associated Documents

No specific provision

## G. Reference

No specific provisions

### Section G Attachment 1

No specific provision

### Section G Attachment 2

No specific provision

### Section G Attachment 3

No specific provision

### Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |

## A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4.1
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators
   - **4.2.** Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date:**
   - **5.1.** The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements and Measures

**R1.** Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operational Planning]*

**1.1.** Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

**M1.** The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

**R2.** Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

**M2.** Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

**R3.** Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

**M3.** Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

**R4.** The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**4.1** If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

**M4.** Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

**R5.** Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**5.1.** The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

**5.2.** The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

**5.3.** The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

**M5.** The Transmission Operator shall have evidence of a documented voltage or Reactive Power Schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

**R6.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**M6.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

## C. Compliance

**1. Compliance Monitoring Process:**

**1.1. Compliance Enforcement Authority:**

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

**1.2. Evidence Retention:**

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

The Transmission Operator shall retain evidence for Measures 1 through 6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

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

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

**1.4. Additional Compliance Information:**

None

## Table of Compliance Elements

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1** | **Operational Planning** | **High** | N/A | N/A | N/A | The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band). |
| **R2** | **Real-time Operations, Same-day Operations, and Operational Planning** | **High** | N/A | N/A | The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL. | The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL. |
| **R3** | **Real-time Operations, Same-day Operations, and Operational Planning** | **High** | N/A | N/A | The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL. | The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL. |

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R4** | **Operations Planning** | **Lower** | N/A | N/A | The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator. | The Transmission Operator does not have exemption criteria. |
| **R5** | **Operations Planning** | **Medium** | N/A | The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request. | The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators. | The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators.<br><br>Or<br><br>The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the |

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | | | voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). |
| **R6** | **Operations Planning** | **Lower** | The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings. | N/A | N/A | The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings. |

## D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

**Requirements**

**E.A.13** Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

**E.A.14** Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

**E.A.15** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*

**E.A.16** Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**E.A.17** Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**E.A.18** Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

**E.A.18.1.** Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

**E.A.18.2.** Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

**Measures**[1]

**M.E.A.13** Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

**M.E.A.14** The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

**M.E.A.15** Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

**M.E.A.16** The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

**M.E.A.17** The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

**M.E.A.18** If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

[1] The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

## Violation Severity Levels

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **E.A.13** | For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area. | For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area. | For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area. | For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area. |
| **E.A.14** | The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area. | The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area. | The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area. | The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area. |
| **E.A.15** | The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less | The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but | The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of | The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules. |

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | than 25% of the voltage schedules. | less than 50% of the voltage schedules. | the voltage schedules. | |
| **E.A.16** | The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator. | The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator. | The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator. | The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator. |
| **E.A.17** | The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator. | The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator. | The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator. | The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator. |

| E # | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| **E.A.18** | N/A | The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading. | The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading. | The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading. |

## E. Interpretations

None.

## F. Associated Documents

None.

## Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

### Rationale:

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

**Rationale for R1:**

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2*)* System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

**Rationale for R2:**

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

**Rationale for R3:**

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

**Rationale for R4:**

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

**Rationale for R5:**

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage Schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

**Rationale for R6:**

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | April 1, 2005 | Effective Date | New |
| 1 | August 2, 2006 | BOT Adoption | Revised |
| 1 | June 18, 2007 | FERC approved Version 1 of the standard. | Revised |
| 1 | July 3, 2007 | Added "Generator Owners" and "Generator Operators" to Applicability section. | Errata |
| 1 | August 23, 2007 | Removed "Generator Owners" and "Generator Operators" to Applicability section. | Errata |
| 2 | August 5, 2010 | Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879. | Revised |
| 2 | January, 10 2011 | FERC issued letter order approving the addition of LSEs and Controllable Load to the standard. | Revised |
| 3 | May 9, 2012 | Adopted by NERC Board of Trustees; Modified to add a WECC region variance | Revised |
| 3 | June 20, 2013 | FERC issued order approving VAR-001-3 | Revised |
| 3 | November 21, 2013 | R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) | Revised |
| 4 | February 6, 2014 | Adopted by NERC Board of Trustees | Revised |
| 4 | August 1, 2014 | FERC issued letter order issued approving VAR-001-4 | |
| 4.1 | August 25, 2015 | Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power | Errata |
| 4.1 | November 13, 2015 | FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000 | Errata |

**Appendix QC-VAR-001-4.1**
**Provisions specific to the standard VAR-001-4.1 applicable in Québec**

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** Voltage Reactive Control
2. **Number:** VAR-001-4.1
3. **Purpose:** No specific provision
4. **Applicability:**

   **Functions**

   No specific provision.

   **Facilities**

   This standard only applies to the facilities of the Main Transmission System (RTP).

5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements and Measures

**Specific provision applicable to requirement R6:**

The Transmission Operators is not required to provide documentation to the Generator Owner specifying necessary tap changes, a timeframe for making the changes and technical justification for these changes considering that the Transmission Operator will give instructions based on the voltage to be maintained on the transmission system.

## C. Compliance

1. **Compliance Monitoring Process**

   **1.1. Compliance Enforcement Authority**

   The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

   **1.2. Evidence Retention**

   No specific provision

   **1.3. Compliance Monitoring and Assessment Processes**

   No specific provision

### 1.4. Additional Compliance Information

No specific provision

## Table of Compliance Elements

No specific provision

## D. Regional Variances

No specific provision

## E. Interpretations

No specific provision

## F. Associated Documents

No specific provision

## Guidelines and Technical Basis

No specific provision

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |
| | | | |

## A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-3
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Generator Operator
   - **4.2.** Generator Owner
5. **Effective Dates**

   The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, VAR-002-3 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

## B. Requirements and Measures

**R1.** The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- That the generator is being operated in start-up,[1] shutdown,[2] or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.

**M1.** The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

**R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within each generating Facility's capabilities[4]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

**2.1.** When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

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[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

**2.2.** When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

**2.3.** Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

**M2.** In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

**R3.** Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

**M3.** The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

**R4.** Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the

Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

**M4.** The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.

**R5.** The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

**5.1.** For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

**5.1.1.** Tap settings.

**5.1.2.** Available fixed tap ranges.

**5.1.3.** Impedance data.

**M5.** The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

**R6.** After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*

**6.1.** If the Generator Owner cannot comply with the Transmission Operator’s specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.

**M6.** The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator’s documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator’s step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

## C. Compliance

### 1. Compliance Monitoring Process:

#### 1.1. Compliance Enforcement Authority:

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

#### 1.2. Evidence Retention:

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

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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

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

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

#### 1.4. Additional Compliance Information:

None.

## Table of Compliance Elements

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1** | **Real-time Operations** | **Medium** | N/A | N/A | N/A | Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1. |
| **R2** | **Real-time Operations** | **Medium** | N/A | N/A | The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator. | The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator.<br><br>OR<br><br>The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage.<br><br>OR<br><br>The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any |

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | | | explanation. |
| **R3** | **Real-time Operations** | **Medium** | N/A | N/A | N/A | The Generator Operator did not make the required notification within 30 minutes of the status change. |
| **R4** | **Real-time Operations** | **Medium** | N/A | N/A | N/A | The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change. |
| **R5** | **Real-time Operations** | **Lower** | N/A | N/A | The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3. | The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3. |
| **R6** | **Real-time Operations** | **Lower** | N/A | N/A | N/A | The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications.<br><br>OR |

| R # | Time Horizon | VRF | Violation Severity Levels | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | | | The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications. |

## D. Regional Variances

None.

## E. Interpretations

None.

## F. Associated Documents

None.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | 5/1/2006 | Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3. | July 5, 2006 |
| 1a | 12/19/2007 | Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007 | Revised |
| 1a | 1/16/2007 | In Section A.2., Added “a” to end of standard number.<br>Section F: added “1.”; and added date. | Errata |
| 1.1a | 10/29/2008 | BOT adopted errata changes; updated version number to “1.1a” | Errata |
| 1.1b | 3/3/2009 | Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009 | Revised |
| 2b | 8/16/2012 | Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b. Adopted by Board of Trustees. | Revised |
| 2b | 4/16/2013 | FERC Order issued approving VAR-002-2b | |
| 3 | 5/6/2014 | Adopted by the NERC Board of Trustees | |
| 3 | 8/1/2014 | FERC issued letter order approving VAR-002-3 | |

## Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

### Rationale:

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

**Rationale for R1:**

This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

**Rationale for R2:**

Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

**Rationale for R3:**

This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

**Rationale for R4:**

This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.

**Rationale for R5:**

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

**Rationale for R6:**

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.

**Appendix QC-VAR-002-3**
**Provisions specific to the standard VAR-002-3 applicable in Québec**

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

## A. Introduction

1. **Title:** Generator Operation for Maintaining Network Voltage Control
2. **Number:** VAR-002-3
3. **Purpose:** No specific provision
4. **Applicability:**

   **Functions**

   No specific provision.

   **Facilities**

   This standard only applies to the facilities of the Main Transmission System (RTP).
5. **Effective Date:**

   **5.1.** Adoption of the standard by the Régie de l'énergie: September 30, 2016

   **5.2.** Adoption of the appendix by the Régie de l'énergie: September 30, 2016

   **5.3.** Effective date of the standard and its appendix in Québec: January 1, 2017

## B. Requirements and Measures

**Specific provisions applicable to requirement R2:**

- For Generator Operators that are not Transmission Owners:

  Unless exempted by the Transmission Operator, each Generator Operator shall maintain the voltage or Reactive Power schedule (in accordance with Facility Ratings), at the output of its generating facilities in order to maintain the voltage of the Main Transmission System within prescribed ranges, as directed by the Transmission Operator.

- For Generator Operators that are also Transmission Owners:

  Unless exempted by the Transmission Operator, each Generator Operator that is also a Transmission Owner shall maintain the voltage or Reactive Power schedule (in accordance with Facility Ratings), at the connection points of its network with that of a third party in order to maintain the voltage of the Main Transmission System within prescribed ranges, as directed by the Transmission Operator.

**Specific provision applicable to requirements R5 and R6:**

- Generator Owners are not required to meet requirements R5, R5.1, R5.1.1, R5.1.2, R5.1.3, R6 and R6.1 considering that the Transmission Operator will give instructions based on the voltage to maintain on the transmission system.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

#### 1.2. Evidence Retention

No specific provision

#### 1.3. Compliance Monitoring and Assessment Processes

No specific provision

#### 1.4. Additional Compliance Information

No specific provision

## Table of Compliance Elements

No specific provision

## D. Regional Variances

No specific provision

## E. Interpretations

No specific provision

## F. Associated Documents

No specific provision

## Guidelines and Technical Basis

No specific provision

## Revision History

| Revision | Adoption Date | Action | Change Tracking |
|---|---|---|---|
| 0 | September 30, 2016 | New appendix | New |
| | | | |