ISO New England Operating Procedure No. 24 - Protection Outages, Settings and Coordination (OP-24)

Effective Date: February 26, 2024

Review By Date: February 26, 2026

References:

Glossary of Terms used in North American Electric Reliability Corporation Inc. (NERC) Reliability Standards

NERC Reliability Standard IRO-010 - Reliability Coordinator Data Specification and Collection

NERC Reliability Standard MOD-032 - Data for Power System Modeling and Analysis

NERC Reliability Standard PRC-027 - Coordination of Protection Systems for Performance During Faults

NERC Reliability Standard TOP-003 - Operational Reliability Data

NERC Reliability Standard TPL-001 - Transmission System Planning Performance Requirements

NERC Considerations for Power Plant and Transmission System Protection Coordination Technical Reference Document - Revision 2, System Protection and Control Subcommittee, July 2015

Northeast Power Coordinating Council, Inc. (NPCC) Glossary of Terms

NPCC Reliability Reference Directory #7 – Remedial Action Schemes

ISO New England Inc. Transmission, Markets, and Services Tariff Section I.3.9 Review of Market Participant’s Proposed Plans

ISO New England Inc. Transmission, Markets, and Services Tariff Section II - Open Access Transmission Tariff (OATT) including but not limited to Section II.22.2

ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP-3)

ISO New England Operating Procedure No. 5 - Resource Maintenance and Outage Scheduling (OP-5)

ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14)

ISO New England Planning Procedure No. 5-5 Requirements and Guidelines for Application of Remedial Action Schemes and Automatic Control Schemes (PP5-5)

Table of Contents

I. Definitions

The following definitions are used for the purposes of this Operating Procedure (OP):

Degradation is any Protection System Component failure, or any other condition, that increases: (1) clearing times, (2) the exposure to longer clearing times, or (3) the number of transmission or generation elements tripped from normal clearing.

LCC Initial Protection Notification is a verbal notification issued by the Local Control Center (LCC) to ISO New England (ISO) regarding the potential Degradation of a Protection System Component as further described in Section V.

LCC Protection Outage Notification is a verbal notification issued by the LCC to ISO after the LCC receives an Owner Protection Outage Notification as described in Section V.

Owner Initial Protection Notification is a verbal notification that is issued by the owner of a Protection System Component when it confirms that there is a Protection System Component failure leading to review as described in Section V.

Owner Protection Outage Notification is a verbal notification that is issued by the owner of a Protection System Component once it makes the determination that Degradation of the Protection System Component has occurred and cannot be immediately corrected.

Pilot Protection System is any communication-aided relay scheme (including direct transfer trip of remote ends).

Protection System Component is any element that affects interrupting device tripping or relay input. Protection System Components include, but are not limited to: sensing relays; tripping relays; lockout relays; DC supplies; control circuits from sensing circuits through to the interrupting device trip coil; and communication channels. Protection System Components do not include equipment such as fault recorders and meters that do not directly affect protection operation.

Defined terms used but not defined in this OP shall have the meaning ascribed to them in the ISO New England Transmission, Markets, and Services Tariff or the Glossary of Terms Used in North American Electric Reliability Corporation Inc. (NERC) Reliability Standards or the Northeast Power Coordinating Council, Inc. (NPCC) Glossary of Terms.

II. Purpose

This OP establishes requirements for entities that own transmission or generation equipment to provide protective relay information to the ISO for the collaborative study of Protection System Components and protection systems, including Remedial Action Schemes (RAS) and Automatic Control Schemes (ACS) that protect transmission and generation elements of the Bulk Electric System (BES). It also includes requirements for equipment owners to coordinate protection equipment and relay settings. Lead Market Participants (Lead MPs) for Generator Owners (GOs) shall provide protective device characteristics to the ISO with the understanding that these settings are used for the ISO's reliability studies and system coordination.

This OP requires that, as appropriate, Transmission Owners (TOs), GOs, Generator Operators (GOPs), and Lead MPs for GOs:

- Collaborate or coordinate, as needed, regarding information necessary for protection system characteristic reviews, and coordinate with other entities for new protection systems, modifications to existing protection systems, or changes in transmission system topology that necessitate changes in protection systems. See Sections III and VI or further details regarding coordination and protection characteristics.
- For applicable facilities listed in Section IV, notify LCCs immediately after confirming Protection System Component failure or Degradation as described in Section V.A.
- For applicable facilities listed in Section IV, provide information to the ISO regarding planned Protection System Component outages for protection system changes, testing or maintenance. Planned outage requests are described in Section V.B.
- Provide information to the ISO prior to making any changes to protection characteristics for the protection of selected transmission or generation equipment, except changes that do not significantly impact relay reach or clearing times. This is detailed in Section VI.
- Provide an annual certification that the protection system characteristics as provided pursuant to this OP have been maintained throughout the year and remain accurate.

The ISO uses the information provided pursuant to this OP to calculate system limits such as operating and planning stability limits, determine generation dispatch limits, as well as to further plan and operate the system in a reliable manner.

III. Coordination Between Entities for Protection Systems

In order to meet its responsibilities as a Reliability Coordinator (RC), Transmission Operator (TOP), Planning Coordinator (PC), and Transmission Planner (TP), the ISO's role in determining protection system performance (including RAS and ACS performance) focuses on the following areas:

- Maintaining awareness of the operational status of protection systems, the correct operation of which is relied upon to maintain system reliability
- Obtaining the data needed to properly model the actions of protection systems for system simulations
- Reviewing the impacts of proposed new or modified protection systems on the performance of the New England Transmission System

TOs, TOPs, GOs, and GOPs shall collaborate and, when necessary, coordinate the design, construction, and commissioning of any new or modified protection system with the owners and operators of all other affected facilities. TOs and GOs shall comply with the requirements related to protection systems included in interconnection agreements with other entities. In addition, TOs, TOPs, GOs, and GOPs shall collaborate when changes in generation, transmission, load, or operating conditions could require changes in the protection systems of others.

If protection changes are needed for interconnections with neighboring TOs, GOs, and/or Balancing Authorities (BAs), the TO or GO shall coordinate protection system settings as required with neighboring TOs, GOs, and BAs, including but not limited to, New York and New Brunswick.

Outage coordination for Protection System Components is described in Section V. TOs and Lead MPs for GOs shall:

- notify ISO prior to making changes to protection systems as further described in Section IV; and
- provide the resulting characteristics of each changed protection system for ISO approval as described in Section VI.

Figure 1a shows the planned Protection System/topology change, Protection System Degradation and outage coordination flow diagram. The figure illustrates the individual steps that are necessary when:

- Applicable Protection System Component characteristics are modified
- Protection System Components experience Degradation due to unplanned circumstances
- Planned Protection System Component outages occur
- Topology changes are planned

Figure 1a - Protective Relay Coordination and Outage Reporting Overview Flow Diagram

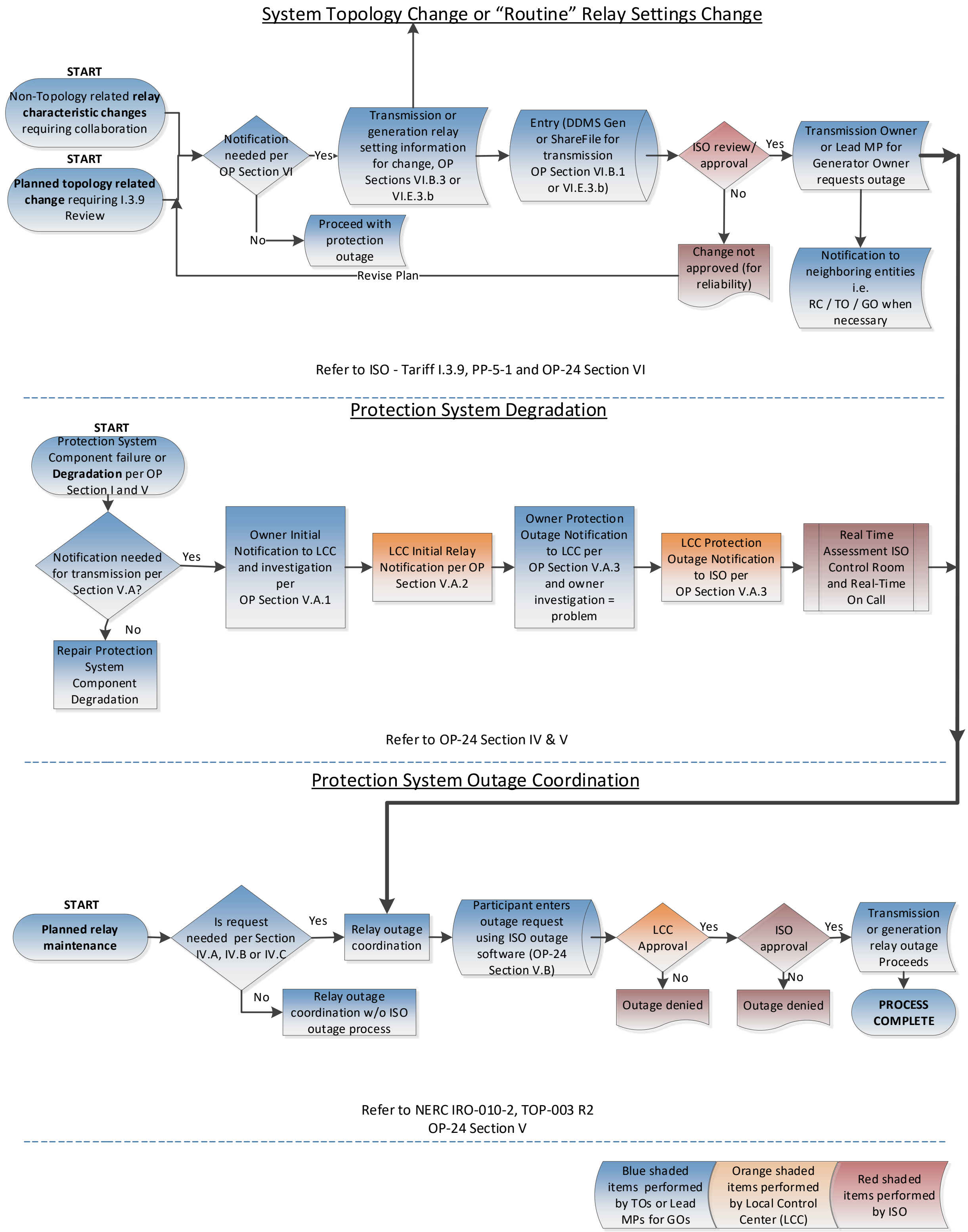
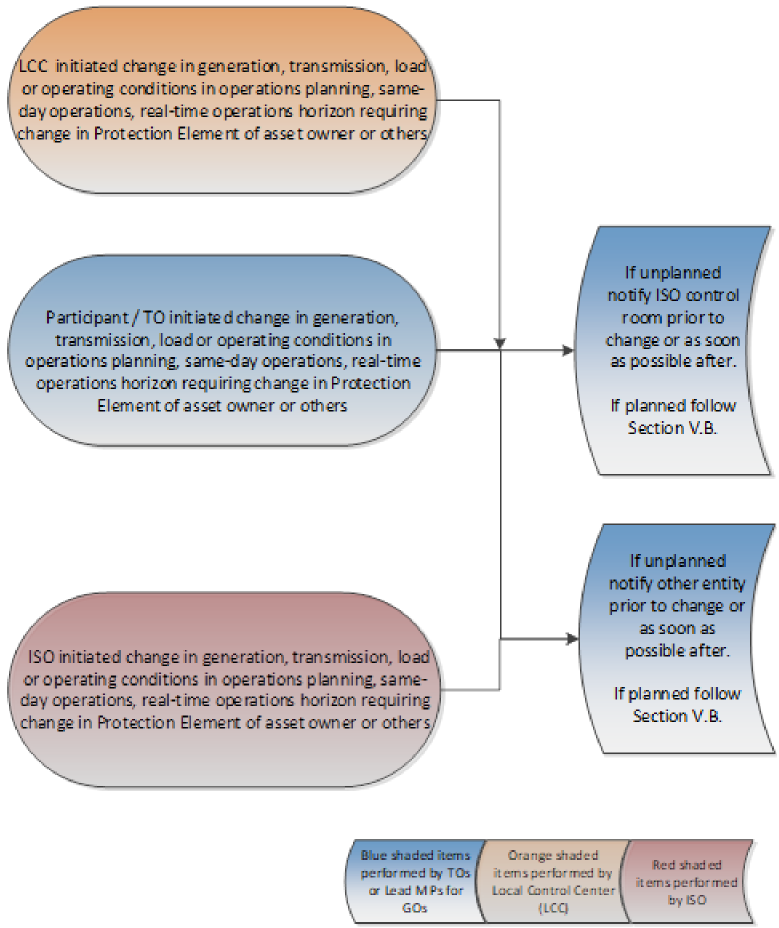


Figure 1b shows the notification flow diagram when changes to Protection System Components are required due to changes in generation, transmission, load, or operating conditions in operations planning, same-day operations, or the Real-Time operations horizon that could require changes in the Protection Systems of others. Generally, the changes addressed by Figure 1b would be temporary protection setting changes during construction sequences.

Figure 1b – Real-Time or Operating Horizon change requiring Protection Change



IV. Facilities Applicable for Notification of Failure or Degradation and Protection Outage Requests

A. Generation Facilities

NOTE

For generators connected to transmission facilities 100 kV and above, it is necessary to provide a notification of failure or Degradation of generator protection, or when a protection outage impacts transmission as shown in Figure 2, since slow clearing could impact the transmission system. Even if a generator is connected to transmission facilities above 100 kV, it is not necessary to request outages for normal maintenance and testing work that could only result in tripping a generator breaker that does not trip BES transmission facilities. Generator interconnection voltage does not establish requirements for generators to provide the characteristics described in Section VI.

This section describes the applicable facilities for, and conditions under which, Lead MPs are required to request generator protection outages that are planned. It also describes the applicable facilities for, and conditions under which, GOs or GOPs are required to provide notifications of Protection System Component failure or Degradation to the ISO. Section V describes how generator entities shall provide notification of Protection System Component failure or Degradation that impacts fault clearing on the BES, and how they shall request Protection System Component outages. Section VI describes applicable facilities for which generator protection characteristics shall be provided.

Protection maintenance and testing that would in any way degrade the level of system protection or system reliability provided by the generator shall not occur while the generator is on-line. GOs or GOPs shall verify that remaining protection is adequate for the equipment if performing on-line maintenance or testing.

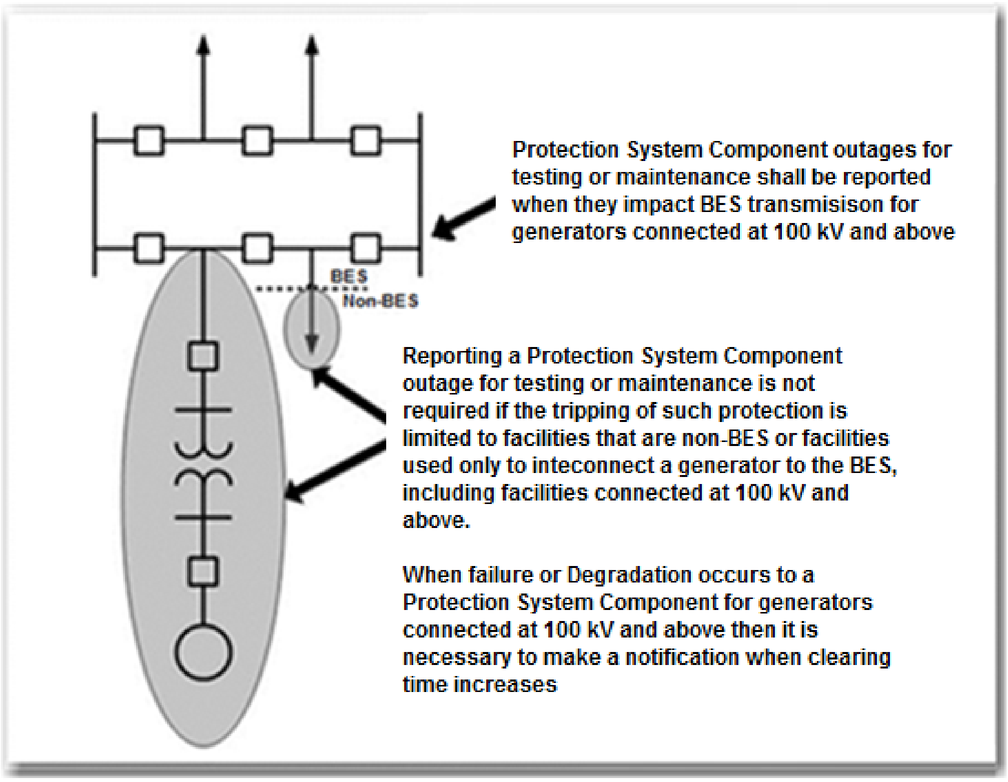
1. Applicable generator facilities for notifications of generator Protection System Component failure or Degradation

Notification is required of any Protection System Component failure or Degradation resulting in slower clearing times for protection that trips breakers on the high or low side of the Generator step-up transformer (GSU) for generators that interconnect to transmission facilities at 100 kV and above. Notifications of Protection System Component failure or Degradation and the subsequent request of a Protection System Component outage are described, respectively, in Sections V.A and V.B. Notification is not required of Protection System Component failure or Degradation for generators that are interconnected below 100 kV.

2. Applicable generator facility requests for Protection System Component maintenance and testing outages

Figure 2 illustrates that for generators connected at 100 kV and above, protection outages that trip related BES transmission facilities shall be reported to the ISO. When Protection System Components that do not impact BES transmission (i.e. the Protection System Components only trip the generator breaker) are tested, it is not necessary for the Lead MP to submit an outage request. Reports of Protection System Component outages are not required for generators that interconnect at voltages below 100 kV.

Figure 2 - Outage Reporting for Generator Protection System Components



B. Transmission Facilities

1. Applicable facilities for notifications of Protection System Component failure or Degradation

TOs shall investigate and immediately notify their respective LCC after confirming any failures or Degradation of Protection System Components that protect any facilities associated with transmission stations as noted in OP-24 Appendix C - Transmission Facilities Required to Report Protection Characteristic, Failures or Degradation (OP-24C). Investigation and notification are described in detail in Section V.A below.

2. Applicable facilities for requesting Protection System Component maintenance and testing outages

OP-24C lists stations for which transmission Protection System Component outages shall be requested. TOs shall submit a protection outage request for any transmission facility connected to a transmission station listed in OP-24C.

C. RAS or ACS

<u>For RAS:</u>
NPCC Reliability Reference Directory #7 Remedial Action Schemes[1] has replaced the term Special Protection System (SPS) with Remedial Action Scheme (RAS). The New England transmission system has a subset of Automatic Control Schemes (ACS) and NPCC approved SPS in service that are now defined as RAS using the following criteria from NPCC Directory #7:

Type I: A RAS, other than a Limited Impact RAS, that recognizes or anticipates abnormal system conditions resulting from design or operating criteria contingencies.
Type II: A RAS, other than a Limited Impact RAS, that recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes.

Limited Impact[2]: A RAS that cannot,by inadvertent operation or failure to operate, cause or contribute to BES or Bulk Power System (BPS) cascading, uncontrolled action, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations[3].

<u>For ACS:</u>
As per the **ISO New England Planning Procedure No. 5-5**[4] **- Requirements And Guidelines For Application Of Remedial Action Schemes And Automatic Control Schemes**, an ACS is defined as any scheme that automatically changes system topology and is not classified as a RAS according to NERC and NPCC's definitions, with exceptions mentioned in the ISO New England Planning Procedure No. 5-5.

TOs or Lead MPs for GOs shall:

- Provide notification to their respective LCC of Protection System Component failures or Degradation and request planned outages associated with, or that affect the operation of a RAS or ACS as described in Section V.

D. Implementation for Notification of Failure or Degradation and Protection Outage Requests

1. For generators, Lead MPs shall submit outage requests and GOs and GOPs shall provide failure or Degradation notifications as applicable under Section IV.A.

[1] NPCC Reliability Reference Directory #7 Remedial Action Schemes
[2] This classification was formerly known as Type III.
[3] Consistent with PRC-012 Supplemental Information, limited impact **RAS** is intended to act upon/mitigate events that are limited to a "contained area". (similar to "local area" within NPCC)
[4] ISO New England Planning Procedure No. 5-5

2. Outage requests and failure or Degradation notifications for transmission Protection System Components are required for any element connected at 100 kV and above for a facility listed in OP-24C.

3. If a transmission facility is added to or removed from OP-24C, then the TO for such facility shall provide outage, failure or Degradation notifications in compliance with this OP on or before 180 calendar days from the effective date of the updated and published OP-24C.

V. Protection System Component Failure Degradation and Outage Coordination

NOTE

TOs and Lead MPs for GOs shall notify ISO prior to making relay settings changes in accordance with Section VI.

This section describes the requirements for notification of Protection System Component failure or Degradation, as well as the requirements for reporting of Protection System Component outages. For a transmission facility with Protection System Components that has multiple owners within New England, protection outage failure or Degradation information shall be reviewed by the protection staff of the entities operating any/all terminal(s) of the jointly operated facility in order to coordinate the Protection System Component outage request.

A. Notification of Generation and Transmission Protection System Component Failure or Degradation:

If Protection System Component failure or Degradation occurs, then it shall be reported as shown in Figure 2. For a generator connected at 100 kV or above or as listed in OP-24C for a transmission facility, the notification process involves several steps by the following entities:

- the entities that own the Protection System Components (i.e. TOs and GOs)
- LCCs
- the ISO

NOTE

The Owner Initial Protection Notification is intended to provide the LCC and the ISO with lead time to develop a plan in case of failure or Degradation that cannot be immediately repaired, coincident with the TO, GO, or GOP determination of parts availability and repair capability.

In order to provide enough time for operator action, while avoiding false indications of system issues, notifications shall be made as follows:

1. An Owner Initial Protection Notification shall be made to the LCC:
    - by a TO immediately after confirming a failure or potential Degradation of an applicable Protection System Component as specified in OP-24C (this Owner Initial Protection Notification shall be based on verification of the actual Protection System Component status);
    - by a GO or GOP immediately after confirming a failure or potential Degradation of a Protection System Component that affects facilities for generators connected at 100 kV and above.

2. If the Protection System Component failure or potential Degradation is confirmed by the TO, GO, or GOP, then the LCC shall issue an LCC Initial Protection Notification to ISO regarding the failure or potential Degradation.
3. When the investigation by the TO, GO or GOP concludes that there is a Degradation of the Protection System Component that cannot be immediately repaired, the TO, GO, or GOP shall issue an Owner Protection Outage Notification to the LCC which, in turn, shall issue an LCC Protection Outage Notification to ISO.
4. Following the LCC Protection Outage Notification regarding the failure or Degradation, the TO, or MP who owns or represents the Protection System Component shall complete an outage request for the Protection System Component as described in Subsection B below.

B. Outage Requests for Generation and Transmission Protection System Component Equipment

Protection System Component outage requests shall be submitted when failure or Degradation occurs or in advance of Protection System Component outages related to capital improvements**,** testing, and maintenance which may also be used to deploy setting changes upon completion of the related ISO review process as described in Section VI. TOs and Lead MPs for GOs shall submit planned Protection System Component outage requests to LCCs and ISO in accordance with the time requirements listed in Table 1 below and in accordance with ISO New England Operating Procedure No. 3 Transmission Outage Scheduling (OP-3). Entities are encouraged to submit Protection System Component outage requests earlier than the Table 1 deadlines, when possible, to reduce the risk of ISO rejection of outage requests, if additional time is needed for collecting information and performing analysis.

Table 1 - Minimum Advance Notice Requirements for Relay / Communication (RLY / COM) Constraint Type

Voltage (kV)	Facility Type	Advance Notice		
		5 Business Days	Informational	Not Required
345, 230	***Special Protection Systems (RAS and ACS)***	**X**		
	Relay and Communication			
	Impact to the Table in Appendix D	**X**		
	No impact to the Table in Appendix D		**X**	
115, 69	***Special Protection Systems (RAS and ACS))***	**X**		
	Relay and Communication			
	Impact to the Table in Appendix D	**X***		
	No impact to the Table in Appendix D		**X***	
	Not listed in OP-24C			**X**

*** Refer to OP-24C for Protection System Component notification requirements**

ISO outage approvals may allow the removal of Protection System Components from service, when equipment is energized, if the TO or Lead MP for GO (consistent with ownership) determines that adequate redundant or backup protection is provided. The ISO shall evaluate the loss of any remaining Protection System Component functionality and document the operating action(s) to be taken if remaining Protection System Component functionality is lost.

TOs and Lead MPs for GOs shall provide additional information regarding clearing times or additional elements tripped by completing Appendix D to this OP - Required Protection Outage Request Form and Examples (OP-24D).

C. Protection System Component Outages of a Duration Greater than 30 Calendar Days

TOs and Lead MPs for GOs shall avoid Protection System Component outages that last longer than 30 calendar days. If a Protection System Component that is involved in the protection of equipment listed in OP-24C is out-of-service for longer than 30 calendar days, then the TOP with information from the TO or Lead MP for the GO shall provide:

- an attachment to the outage request showing progress in restoring the Protection System Component to service; and
- a corrective action plan describing the steps that will be undertaken to restore the Protection System Component to service.

The ISO reserves the right to disconnect from the system, any transmission or generation element that has unacceptable protection performance, which could result in adverse impact on system reliability. The ISO may invoke this right for an outage lasting less than 30 calendar days.

VI. Relay Characteristics Provided to ISO

A. Modifying Relay Settings for Emergencies

When necessary to ensure the reliability of the power system (for example, by reducing the risk of a misoperation), a TO or GO may make relay settings modifications before notifying ISO. Specifically, in such an emergency, a TO or GO may provide the notifications described in Section V within seven (7) Business Days after the date of the emergency, and the notifications shall also include a description of the emergency.

B. Protection System Components for Generating Facilities

1. Applicable Facilities

Lead MPs for GOs shall perform periodic reviews of relay characteristics for generation facilities with a single point of interconnection over 100 kV with gross plant/facility aggregate nameplate rating greater than or equal to 75 MVA and at any other facility where the ISO has indicated in writing to the Lead MP for the GO, that the characteristics are needed for reliability studies.

2. Data Transmittals, Creation of Models, and Protection Updates for Generation Facilities

Lead MPs for GOs with new or modified generation facilities that meet the applicability as described in section VI.B.1 shall provide the required data, using the Dynamics Data Management System (DDMS),[5] at least 90 calendar days prior to Commercial operation along with as-built settings prior to Commercial operation. In addition, the Lead MP for the GO shall promptly and fully respond to any additional data requests and any questions from the ISO regarding the relay setting characteristics.

If, subsequent to the development and certification of the initial PSS/E generator relay models, any relay setting characteristics for a generation facility changes, then the Lead MP for the GO shall develop updated PSS/E generator relay models itself. Appendix A[6] to this OP - Generator Relay Settings (OP-24A) provides guidance that Lead MPs for GOs may use when creating relay models for PSS/E from actual relay settings. Additional information can be found in the document named “Generator Protection Modeling Practice & Guidelines” posted on the ISO’s external website at:

http://www.iso-ne.com/participate/rules-procedures/nerc-npcc

[5] DDMS can be accessed at https://smd.iso-ne.com/

[6] Appendix A is based on the NERC document: Considerations for Power Plant and Transmission System Protection Coordination, Technical Reference Document – Revision 2, System Protection and Control Subcommittee, July 2015.

NOTE

Lead MPs for GOs do not need to inform ISO of changes to protective relays not listed in OP-24 Appendix A. Those changes shall be coordinated in accordance with NERC Standard PRC-027.

Using DDMS, the Lead MP for the GO shall submit, to the ISO, updates to relay settings characteristics and information, including revised PSS/E generator relay models, at least 120 calendar days in advance of making permanent changes to the relay characteristics specified in OP-24A. This will provide ISO time to review the effect of protection changes on system stability performance.

3. **Certification and Recertification of Generator Relay Models**

Lead MPs for GOs shall certify in DDMS that the generator relay models developed pursuant to Section VI.B.2 are accurate, per the timeline established in Section VI.B.2.

Lead MPs for GOs shall recertify, on an annual basis, that generator relay models are accurate. The recertification shall be performed in DDMS as part of the certification of other generator dynamics and other data required pursuant to ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14).

4. **Standard Models and Generator Breaker Tripping Information**

OP-24A includes commonly used PSS/E standard models for relay functions. A Lead MP for the GO may select a different standard PSS/E library model if more appropriate. Provision of user-written models for relays is not acceptable.

5. **Clearing Time Information for GO Owned Substations and Transmission**

Lead MPs for GOs with transmission equipment connected at 100 kV and above (i.e. lines, generator step-up transformers and associated equipment) and generator breakers on the low side of the GSU shall be provided in accordance with Section VI.C and VI.E.

C. Transmission Equipment Data Submittals

1. Transmission Owners that are also Transmission Planners (TO-TPs) shall provide protection characteristics as described below, to the ISO System Protection Working Group (SPWG) ShareFile folder.
2. Generator Owners (GOs) shall provide protection information associated with transmission equipment in the manner specified in the ISO data request.

3. Other Protection Asset Owners shall provide protection information in the manner specified in the ISO data request.

D. Transient Swing Detection Characteristics for Transmission Lines:

1. Model Submittal Requirements

a. Certain ISO-conducted planning studies use a generic distance relay model to monitor for the possible tripping of non-faulted elements due to stable power swings. The generic relay model used is as follows:

(1) Reach equal to 300% of the impedance of the monitored line with all lines in-service and no intentional tripping time delay

(2) In any instances where this generic model shows that a line is susceptible to tripping without a fault during power swings, the ISO shall require that the appropriate TO(s) provide relay models for any relays that could trip a terminal of the line without requiring a permissive signal from the opposite terminal(s) of the line.

b. For multi-terminal lines, the generic relay model used by the ISO shall have a reach equal to 300% of the total impedance to the furthest terminal of the line, without considering infeed current from other terminals.

NOTE

The exclusion described in Section VI.D.1.c. addresses the fact that a permissive relay scheme (such as a Permissive over-reaching transfer trip (POTT) scheme) will not trip unless the apparent impedance at both terminals of the transmission line enters the fault characteristic zone. This can only happen if a point along the transmission line has a voltage equal to zero - meaning that either the line is faulted or the swing is not stable (the two terminals of the line are out-of-step with each other). A directional comparison blocking scheme can act if only one terminal's apparent impedance enters the fault characteristic zone.

c. TOs shall provide relay models to the ISO for any relays with a reach that exceeds 300% of the total impedance of the line, and that operate with an intentional delay less than or equal to 60 cycles. This data shall be required only for relays that could trip one or more terminals of the line without requiring a permissive signal from the opposite terminal(s) of the line. For example, data for step-distance or directional comparison blocking schemes reaching beyond 300% of the total impedance of the line is required; but data for POTT schemes is not required, because these schemes would not act without a permissive signal from the opposite terminal.

d. TOs shall provide all required relay reach modeling information in a DYR file format, usable in the PSS/E software package. Models shall be submitted using the SPWG ShareFile folder within 15 Business Days of an ISO request, or at least 120 days prior to a change resulting in relay reach beyond 300% of line impedance. Changes may require approval pursuant to the timing and other requirements of Section I.3.9 of the ISO Tariff before implementation.

2. **Implementation**

TOs shall provide actual models for lines that are susceptible to tripping during transient swings as outlined in Sections VI.D.1.c and VI.D.1.d. When making any settings changes in accordance with Section VI.D.1.d, TOs shall provide the information in accordance with that Section.

TOs shall provide relay models for relays that reach beyond 300% of the line impedance, as described in VI.D.1.c.

E. Fault Clearing Information for Lines, Transformers and Shunt Devices:

1. Equipment For Which Fault Clearing Data Is Required

The ISO uses fault-clearing information to simulate clearing of criteria required faults in assessing the acceptable performance of the power system. TOs and, as determined under Section VI.B.5, Lead MPs for GOs (collectively, Protection Asset Owners) shall provide the fault clearing information as specified in Appendix B to this OP - Transmission Relaying Characteristics (OP-24B) for all equipment with at least one terminal connected to 100 kV and above, as well as for all PTF facilities at 69 kV. Protection Asset Owners shall coordinate responses for a line that connects substations with different owners.

2. Implementation

a. As applicable, Protection Asset Owners shall provide fault-clearing information for all equipment with at least one terminal connected at 100 kV and above, as well as for all PTF facilities at 69 kV within 180 calendar days of the original request.

b. The ISO may request protection system data for a limited set of specific transmission or generation elements that is not already provided pursuant to OP-24B. Protection Asset Owners shall respond to such requests by providing fault clearing information according to the following timelines:

   (1) if needed for planning purposes, within 20 Business Days of receiving a request from the ISO; or

   (2) if needed for operations purposes, within 2 Business Days of receiving a request from the ISO.

c. The ISO shall initiate an annual certification that the clearing times provided by Protection Asset Owners are accurate. Each Protection Asset Owner shall certify that the clearing times on file with the ISO are currently valid and correct.

3. Data Required and Submission Process

> **NOTE**
>
> Protection Asset Owners shall provide a "proxy" clearing time representing the most conservative clearing time by ground overcurrent relays. TOs shall provide the exact ground overcurrent relay model for a given transmission element if the ISO determines that the simulation fails using the "proxy" clearing time.
>
> Protection Asset Owners shall provide the overcurrent relay model in a format acceptable to the ISO (relay settings data is not acceptable).

a. The format for protection system data submittal is included in OP-24B. OP-24B requires default clearing time information for transmission lines, transformers, substation equipment, and breakers. When the equipment does not clear within the default clearing time, it is necessary to provide additional information on the protection characteristics in OP-24B. As part of this process, any data on step-distance on transmission lines shall be submitted if these schemes are the fastest protection schemes in one of the two redundant systems. Completed versions of OP-24B, shall be submitted as specified in section VI.C.

b. Any change to the existing protection at substations that are listed in OP-24C that affects clearing times or relay reaches, except for those where both the pre- and post- change clearing times are less than or equal to ($\leq$) the applicable default clearing time, or any new protection subject to OP-24B (e.g. due to topology changes), shall be submitted to ISO at least 60 calendar days in advance of energization. This time requirement does not apply to emergency conditions as described in Section VI.A, or temporary changes of less than one year, for construction or replacements. This requirement also does not apply to all other elements in OP-24B that are not at the substations listed in OP-24C, and any changes to protection systems to these facilities shall be reported as a part of the annual recertification. These changes may require approval pursuant to Section I.3.9 of the ISO Tariff if applicable. All changes and updates shall be submitted as specified in section VI.C.

c. In addition to the information described above, certain ISO planning studies consider contingencies with delayed fault-clearing due to the failure of a non-redundant protection package to protect the faulted element as designed, such as for one of the following:

   (1) Generator

   (2) Transmission circuit

   (3) Transformer

   (4) Shunt device

   (5) Bus section

For these studies, the ISO shall request additional information and the TO shall provide the data in accordance with the description contained in the request. This information shall be provided within 20 Business Days of receiving the request from the ISO.

VII. Specific Relay Settings Information

A. Protection System Components for Generating Facilities

OP-14 includes additional specifications for generator protection settings.

B. Transmission Automatic Reclosing Requirements

TOs shall provide the time delay for automatic line reclosing pursuant to OP-24B. Automatic line reclosing, if set properly, expedites the return-to-service of a line following a temporary fault. However, reclosing may cause system and generator instability, generator or transmission equipment fatigue and failure, as well as other issues that could have an adverse impact on reliability. In order to balance the varied needs of the New England Transmission System, the ISO shall review the data, submitted by the TOs, on the time delay for automatic line reclosing. The ISO shall apply the following principles in its review:

1. High-speed automatic reclosing [referred to as high-speed reclosing in NERC Reliability Standards and High-Speed Auto reclosing in the NPCC Glossary of Terms], is automatic reclosing that occurs in less than one second, and is not permitted for use on the New England Transmission System. The ISO will not support the installation and use of high-speed automatic reclosing in New England. The ISO shall be promptly notified about any existing high-speed automatic reclosing. The ISO may order that any existing high-speed automatic reclosing be taken out-of-service until technical analysis can confirm that it does not cause an adverse impact to system reliability. The ISO shall evaluate automatic reclosing occurring at one second for acceptance on a case-by-case basis; the ISO may order that any existing one second automatic reclosing be taken out-of-service until the technical analysis can confirm that it does not cause an adverse impact to system reliability.

2. Automatic reclosing slower than 1 second but faster than:

    - 5 seconds for 230 kV, 138 kV, and 115 kV facilities; or
    - 15 seconds for 345 kV facilities;

    shall be reviewed by the ISO with a potential recommendation to reset the reclosing time delay if the ISO finds an adverse impact on system reliability.

3. Automatic reclosing equal to or slower than

    - 5 seconds for 230 kV, 138 kV and 115 kV facilities; or
    - 15 seconds for 345 kV facilities;

    shall typically not require ISO review.

    The above time delays refer to any interval between consecutive attempts to automatically reclose.

    These settings fall within the typical reclosing assumptions used in ISO's past planning and operating studies and, as such, have raised no reliability concerns. However, if the ISO finds an adverse impact on system reliability, then the ISO may recommend that the reclosing time delay be reset.

VIII. OP-24 Revision History

Rev No.	Date	Reason
0	02/01/19	Initial version
1	08/02/19	Globally made grammar changes required by the changes made to Appendix C (i.e., replaced document content from a link to a diagram to a link to tables of lists); Section IX Appendices, changed Appendix C title;
2	12/07/20	Periodic review by procedure owner; Process changes to reflect work practices and procedures.
3	09/03/21	Updated list of applicable References ; Added Note in Section IV.C for RAS terminology; Deleted sunset language in Section V
4	12/05/22	Periodic review by procedure owner; Removed SPS language; Changed Advance Notice time in Table 1 from 120 hours to 5 Business Days to allow for adequate technical review time for relay outages; Minor grammar changes throughout.
5	02/26/24	Biennial review by procedure owner; Expanded OP-24 Appendix B to apply to all elements with at least one terminal at 100kV or above and all PTF facilities at 69 kV in lieu of only providing clearing time information for all stations on OP-24 Appendix C; Conforming changes to other parts of the document to decouple OP-24C from OP-24B; Revised section VI.B to clarify the clearing time information requested from GOs; Amended section VI.C to specify how clearing time information should be provided; Updated implementation plan sections of the document to include proposed implementation schedule and remove obsolete language from original OP-24 implementation plan

IX. Appendices

Appendix A - Generator Relay Settings

Appendix B - Transmission Relaying Characteristics

Appendix C - Transmission Facilities Required to Report Protection Characteristic Updates, Failures or Degradation (Confidential)

Appendix D - Required Protection Outage Request Form and Examples