

A. Introduction

1. **Title:** Automatic Generation Control

2. **Number:** BAL-005-0.1b

3. **Purpose:**

This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. **Applicability:**

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. **Effective Date:** ~~May 13, 2009~~ [TBD](#)

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities, [including its Generator Interconnection Facility](#), operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

- R7.** The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.
- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.
- R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

- R16.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.
- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

- 1.1.1.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.
- 1.1.2.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

- 1.3.1.** Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.
- 1.3.2.** Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial.	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008.	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date and Footer	Addition
1b	TBD	Modified R1.1 to include its Generator Interconnection Facility	Addition

Appendix 1

Request: PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- Only equipment within the operations control room
- Only equipment that provides values used to calculate AGC ACE
- Only equipment that provides values to its SCADA system
- Only equipment owned or operated by the BA
- Only to new or replacement equipment
- To all equipment that a BA owns or operates

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R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation:

As noted in the existing interpretation, BAL-005-1 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-~~X1~~
3. **Purpose:** NERC Standards CIP-002 through CIP-009 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed. Responsible Entities should interpret and apply Standards CIP-002 through CIP-009 using reasonable business judgment.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002 requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. **Applicability:**
 - 4.1. Within the text of Standard CIP-002, “Responsible Entity” shall mean:
 - 4.1.1 Reliability Coordinator.
 - 4.1.2 Balancing Authority.
 - 4.1.3 Interchange Authority.
 - 4.1.4 Transmission Service Provider.
 - 4.1.5 Transmission Owner.
 - 4.1.6 Transmission Operator.
 - 4.1.7 Generator Owner.
 - 4.1.8 Generator Operator.
 - 4.1.9 Load Serving Entity.
 - 4.1.10 NERC.
 - 4.1.11 Regional Reliability Organizations.
 - 4.2. The following are exempt from Standard CIP-002:
 - 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
 - 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
5. **Effective Date:** ~~June 1, 2006~~TBD

B. Requirements

The Responsible Entity shall comply with the following requirements of Standard CIP-002:

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
 - R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
 - R1.2.** The risk-based assessment shall consider the following assets:
 - R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
 - R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
 - R1.2.3.** Generation resources, [including the Generator Interconnection Facility](#), that support the reliable operation of the Bulk Electric System.
 - R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators [and their attendant Generator Interconnection Facility](#), and substations in the electrical path of transmission lines used for initial system restoration.
 - R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
 - R1.2.6.** Special Protection Systems that support the reliable operation of the Bulk Electric System.
 - R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002, Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
 - R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
 - R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
 - R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — A senior manager or delegate(s) shall approve annually the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s

approval of the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

The following measures will be used to demonstrate compliance with the requirements of Standard CIP-002:

- M1.** The risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The list of Critical Assets as specified in Requirement R2.
- M3.** The list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

- 1.1.1** Regional Reliability Organizations for Responsible Entities.
- 1.1.2** NERC for Regional Reliability Organization.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

- 1.3.1** The Responsible Entity shall keep documentation required by Standard CIP-002 from the previous full calendar year
- 1.3.2** The compliance monitor shall keep audit records for three calendar years.

1.4. Additional Compliance Information

- 1.4.1** Responsible Entities shall demonstrate compliance through self-certification or audit, as determined by the Compliance Monitor.

2. Levels of Non-Compliance

- 2.1 Level 1:** The risk assessment has not been performed annually.
- 2.2 Level 2:** The list of Critical Assets or Critical Cyber Assets exist, but has not been approved or reviewed in the last calendar year.
- 2.3 Level 3:** The list of Critical Assets or Critical Cyber Assets does not exist.
- 2.4 Level 4:** The lists of Critical Assets and Critical Cyber Assets do not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	01/16/06	R3.2 — Change “Control Center” to “control center”	03/24/06
X	TBD	Modified R1.2.3 to include the Generator Interconnection Facility and R1.2.4 to	Addition

		include a Generator Interconnection Facility	

A. Introduction

1. **Title:** **Emergency Operations Planning**
2. **Number:** EOP-001-~~X0~~
3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.
4. **Applicability**
 - 4.1. Balancing Authorities.
 - 4.2. Transmission Operators.
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
- R2. The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.
- R3. Each Transmission Operator and Balancing Authority shall:
 - R3.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.
 - R3.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
 - R3.3. Develop, maintain, and implement a set of plans for load shedding.
 - R3.4. Develop, maintain, and implement a set of plans for system restoration.
- R4. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:
 - R4.1. Communications protocols to be used during emergencies.
 - R4.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.
 - R4.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.
 - R4.4. Staffing levels for the emergency.
- R5. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

- R6.** The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.
- R7.** The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:
- R7.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.
- R7.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.
- R7.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules, [including outages to the Generator Interconnection Facility](#), -to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)
- R7.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

- M1.** The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.
- M2.** The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Standard EOP-001-~~X~~⁰ — Emergency Operations Planning

- 2.1. **Level 1:** One of the applicable elements of Attachment 1-EOP-001-~~0~~^X has not been addressed in the emergency plans.
- 2.2. **Level 2:** Two of the applicable elements of Attachment 1-EOP-001-~~0~~^X have not been addressed in the emergency plans.
- 2.3. **Level 3:** Three of the applicable elements of Attachment 1-EOP-001-~~X~~⁰ have not been addressed in the emergency plans.
- 2.4. **Level 4:** Four or more of the applicable elements of Attachment 1-EOP-001-~~0~~^X have not been addressed in the emergency plans or a plan does not exist.

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
X	TBD	Modified R7.3 to include the Generator Interconnection Facility	Addition

Attachment 1-EOP-001-0X

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.
2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.
3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.
4. System energy use — The reduction of the system’s own energy use to a minimum.
5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
6. Load management — Implementation of load management and voltage reductions, if appropriate.
7. Optimize fuel supply — The operation of all generating sources to optimize the availability.
8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.
9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.
10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.
11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.
12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.
13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.
14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.
15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

A. Introduction

1. **Title:** Load Shedding Plans
2. **Number:** EOP-003-X1
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.
 - 4.3. Generator Operators.
5. **Effective Date:** ~~January 1, 2007~~ TBD

B. Requirements

- R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
- R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.
- R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.
- R4. A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.
- R5. A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
- R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.
- R7. The Transmission Operator, Generator Operator, -and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.
- R8. Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

- M1.** Each Transmission Operator and Balancing Authority that has or directs the deployment of undervoltage and/or underfrequency load shedding facilities, shall have and provide upon request, its automatic load shedding plans.(Requirement 2)
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

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

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

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

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

1.5. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not Applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Does not have an automatic load shedding plan as specified in R2.

2.4.2 Does not have manual load shedding plans as specified in R8.

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
<u>X</u>	<u>TBD</u>	<u>Modified R7 to include Generator Operator.</u> <u>Added Generator Operator to Applicability Section.</u>	<u>Addition</u>

A. Introduction

1. **Title:** **Disturbance Reporting**
2. **Number:** EOP-004-~~X1~~
3. **Purpose:** Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
 - 4.3. Transmission Operators.
 - 4.4. Generator Operators.
 - 4.5. Load Serving Entities.
 - 4.6. Regional Reliability Organizations.
5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

- R1. Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.
- R2. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities, [including those for the Generator Interconnection Facility](#).
- R3. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.
 - R3.1. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.
 - R3.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.
 - R3.3. Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s)

and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

- R3.4.** If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.
- R4.** When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.
- R5.** The Regional Reliability Organization shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

C. Measures

- M1.** The Regional Reliability Organization shall have and provide upon request as evidence, its current regional reporting procedure that is used to facilitate preparation of preliminary and final disturbance reports. (Requirement 1)
- M2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load-Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, the preliminary report, computer printouts, operator logs, or other equivalent evidence that will be used to confirm that it prepared and delivered the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1.
- M3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that has a reportable incident shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it provided information verbally

as time permitted, when system conditions precluded the preparation of a report in 24 hours. (Requirement 3.3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations.

Regional Reliability Organizations shall be responsible for compliance monitoring of Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load-serving Entities.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Regional Reliability Organization shall have its current, in-force, regional reporting procedure as evidence of compliance. (Measure 1)

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and/or Load Serving Entity that is either involved in a Bulk Electric System disturbance or has a reportable incident shall keep data related to the incident for a year from the event or for the duration of any regional investigation, whichever is longer. (Measures 2 through 4)

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.

1.4. Additional Compliance Information

See Attachments:

- EOP-004 Disturbance Reporting Form
- Table 1 EOP-004

2. Levels of Non-Compliance for a Regional Reliability Organization

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: No current procedure to facilitate preparation of preliminary and final disturbance reports as specified in R1.

3. Levels of Non-Compliance for a Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load- Serving Entity:

3.1. Level 1: There shall be a level one non-compliance if any of the following conditions exist:

3.1.1 Failed to prepare and deliver the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports to NERC within 24 hours of its recognition as specified in Requirement 3.1

3.1.2 Failed to provide disturbance information verbally as time permitted, when system conditions precluded the preparation of a report in 24 hours as specified in R3.3

3.1.3 Failed to prepare a final report within 60 days as specified in R3.4

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable

3.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	May 23, 2005	Fixed reference to attachments 1-EOP-004-0 and 2-EOP-004-0, Changed chart title 1-FAC-004-0 to 1-EOP-004-0, Fixed title of Table 1 to read 1-EOP-004-0, and fixed font.	Errata
0	July 6, 2005	Fixed email in Attachment 1-EOP-004-0 from info@nerc.com to esisac@nerc.com .	Errata

Standard EOP-004-X4 — Disturbance Reporting

0	July 26, 2005	Fixed Header on page 8 to read EOP-004-0	Errata
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R2 to include the Generator Interconnection Facility.</u>	<u>Addition</u>

Attachment 1-EOP-004 NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (esisac@nerc.com) by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at esisac@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
 - a. Modification of operating procedures.
 - b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
 - c. Identification of valuable lessons learned.
 - d. Identification of non-compliance with NERC standards or policies.
 - e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
 - f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
 - a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
 - b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.

6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
 - a. Sustained voltage excursions equal to or greater than $\pm 10\%$, or
 - b. Major damage to power system components, or
 - c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.
7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. <div style="text-align: right;">Date:(mm/dd/yy) Time/Zone:</div>		
5.	Did the disturbance originate in your system?	Yes <input type="checkbox"/> No <input type="checkbox"/>	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. <div style="text-align: right;">MW Total List generation tripped</div>		
8.	Frequency. <div style="text-align: right;">Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):</div>		
9.	List transmission lines tripped (specify voltage level of each line).		
10.	Demand tripped (MW): Number of affected Customers:	FIRM	INTERRUPTIBLE

	Demand lost (MW-Minutes):		
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

Attachment 2-EOP-004 U.S. Department of Energy Disturbance Reporting Requirements

Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form EIA-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.

6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption. Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: <ftp://ftp.eia.doe.gov/pub/electricity/eiafor417.doc>.

Table 1-EOP-004-0 Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies				
Incident No.	Incident	Threshold	Report Required	Time
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels $\leq 50\%$ of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	$\geq 50,000$ for 1 hour or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				

All entities required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.

Incident No.	Incident	Threshold	Report Required	Time
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	<ul style="list-style-type: none"> • Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS 	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day

All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.

Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.

A. Introduction

1. **Title:** Plans for Loss of Control Center Functionality
2. **Number:** EOP-008-~~X0~~
3. **Purpose:** Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Reliability Coordinators.
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:
 - R1.1. The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.
 - R1.2. The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
 - R1.3. The contingency plan must address monitoring and control of critical transmission facilities, [Generator Interconnection Operational Interface](#), generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.
 - R1.4. The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
 - R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
 - R1.6. The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.
 - R1.7. The plan shall be reviewed and updated annually.
 - R1.8. Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

C. Measures

- M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

D. Compliance

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

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

1.3. Data Retention

The contingency plan for loss of primary control facility must be available for review at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: NA

2.2. Level 2: A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

2.3. Level 3: A contingency plan has been implemented, but does not include all of the elements contained in Requirements R1.1–R1.8.

2.4. Level 4: A contingency plan has not been developed, implemented, and tested.

E. Regional Differences

1. 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
X	TBD	Modified R1.3 to include Generator Interconnection Operational Interface	Addition

A. Introduction

1. **Title:** Facility Connection Requirements
2. **Number:** FAC-001-~~0~~X
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements.
4. **Applicability:**
 - 4.1. Transmission Owner
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:
 - R1.1. Generation facilities, including the Generator Interconnection Facility.
 - R1.2. Transmission facilities, and
 - R1.3. End-user facilities
- R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:
 - R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
 - R2.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.
 - R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.
 - R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.
 - R2.1.4. Breaker duty and surge protection.
 - R2.1.5. System protection and coordination.
 - R2.1.6. Metering and telecommunications.
 - R2.1.7. Grounding and safety issues.
 - R2.1.8. Insulation and insulation coordination.
 - R2.1.9. Voltage, Reactive Power, and power factor control.
 - R2.1.10. Power quality impacts.
 - R2.1.11. Equipment Ratings.
 - R2.1.12. Synchronizing of facilities.

R2.1.13. Maintenance coordination.

R2.1.14. Operational issues (abnormal frequency and voltages).

R2.1.15. Inspection requirements for existing or new facilities.

R2.1.16. Communications and procedures during normal and emergency operating conditions.

R3. The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization, and NERC on request (five business days).

C. Measures

M1. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R1.

M2. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all requirements stated in Reliability Standard FAC-001-0_R2.

M3. The Transmission Owner shall make available (to its Compliance Monitor) for inspection evidence that it met all the requirements stated in Reliability Standard FAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (five business days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Facility connection requirements were provided for generation, transmission, and end-user facilities, per Reliability Standard FAC-001-0_R1, but the document(s) do not address all of the requirements of Reliability Standard FAC-001-0_R2.

2.2. Level 2: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, but the document(s) provided address all of the requirements of Reliability Standard FAC-001-0_R2.

2.3. Level 3: Facility connection requirements were not provided for all three categories (generation, transmission, or end-user) of facilities, per Reliability Standard FAC-001-0_R1, and the document(s) provided do not address all of the requirements of Reliability Standard FAC-001-0_R2.

Standard FAC-001-0-X — Facility Connection Requirements

- 2.4. **Level 4:** No document on facility connection requirements was provided per Reliability Standard FAC-001-0_R3.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>X</u>	<u>TBD</u>	<u>Modified R1.1 to include the Generator Interconnection Facility</u>	<u>Addition</u>

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**
2. **Number:** FAC-003-~~X1~~
3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).
4. **Applicability:**
 - 4.1. Transmission Owner.
 - 4.2. Regional Reliability Organization.
 - 4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.
 - 4.4. Generator Owner.
 - 4.5. This standard shall apply to the Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.)
5. **Effective Dates:**
 - ~~5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.~~
 - ~~5.2.5.1. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4. TBD~~

B. Requirements

- R1. The Transmission Owner and Generator Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's and Generator Owner's objectives, practices, approved procedures, and work specifications¹.
 - R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's or Generator Owner's transmission lines.
 - R1.2. The Transmission Owner and Generator Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner and Generator Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of

¹ ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner and Generator Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner or Generator Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner and Generator Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific and Generator Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner or Generator Owner, to perform their duties.

R1.4. Each Transmission Owner and Generator Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner or Generator Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner and Generator Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner and Generator Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into

consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner and Generator Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner and Generator Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner or Generator Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner or Generator Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner, Generator Owner, or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner or Generator Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner or Generator Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

- M1.3.** The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner’s TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.
- M1.4.** The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner’s standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.
- M1.5.** The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.
- M2.** The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.
- M3.** The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO’s designee, as identified in Requirement 3.
- M4.** The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO
NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

- 2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;
- 2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.
- 2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

- 2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;
- 2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;
- 2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

- 2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;
- 2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> 1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer. 	01/20/06
<u>X</u>	<u>TBD</u>	<p><u>Modified the Applicability Section to include the Generator Owner and Generator Interconnection Facility above 200 kV that exceed two spans from the generator property line or are otherwise deemed critical by the Regional Entity below 200 kV (subject to the two-span criteria.).</u></p> <p><u>Included Generator Owner into the following Requirements: R1, R1.1, R1.2, R1.2.1, R1.2.2, R1.3, R1.4, R1.5, R2, R3,</u></p>	<u>Addition</u>

Standard FAC-003-X4 — Transmission Vegetation Management Program

		R3.2, and R3.3	

A. Introduction

1. **Title:** Facility Ratings Methodology
2. **Number:** FAC-008-~~X~~4
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
 - 4.1. Transmission Owner
 - 4.2. Generator Owner
5. **Effective Date:** ~~August 7, 2006~~TBD

B. Requirements

- R1. The Transmission Owner and Generator Owner shall each document its current methodology used for developing Facility Ratings (Facility Ratings Methodology) of its solely and jointly owned Facilities, including the Generator Interconnection Facility. The methodology shall include all of the following:
 - R1.1. A statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
 - R1.2. The method by which the Rating (of major BES equipment that comprises a Facility) is determined.
 - R1.2.1. The scope of equipment addressed shall include, but not be limited to, generators, the Generator Interconnection Facility, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.
 - R1.2.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.
 - R1.3. Consideration of the following:
 - R1.3.1. Ratings provided by equipment manufacturers.
 - R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards).
 - R1.3.3. Ambient conditions.
 - R1.3.4. Operating limitations.
 - R1.3.5. Other assumptions.
- R2. The Transmission Owner and Generator Owner shall each make its Facility Ratings Methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners, and Planning Authorities that have responsibility for the area in which the associated Facilities are located, within 15 business days of receipt of a request.
- R3. If a Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides written comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall provide a written response to that commenting entity within 45 calendar days of

receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

C. Measures

- M1.** The Transmission Owner and Generator Owner shall each have a documented Facility Ratings Methodology that includes all of the items identified in FAC-008 Requirement 1.1 through FAC-008 Requirement 1.3.5.
- M2.** The Transmission Owner and Generator Owner shall each have evidence it made its Facility Ratings Methodology available for inspection within 15 business days of a request as follows:
 - M2.1** The Reliability Coordinator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Reliability Coordinator Area.
 - M2.2** The Transmission Operator shall have access to the Facility Ratings Methodologies used for Rating Facilities in its portion of the Reliability Coordinator Area.
 - M2.3** The Transmission Planner shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Transmission Planning Area.
 - M2.4** The Planning Authority shall have access to the Facility Ratings Methodologies used for Rating Facilities in its Planning Authority Area.
- M3.** If the Reliability Coordinator, Transmission Operator, Transmission Planner, or Planning Authority provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings Methodology, the Transmission Owner or Generator Owner shall have evidence that it provided a written response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings Methodology and, if no change will be made to that Facility Ratings Methodology, the reason why.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor at least once every three years. New Transmission Owners and Generator Owners shall each demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep all superseded portions of its Facility Ratings Methodology for 12 months beyond the date of the change in that methodology and shall keep all documented comments on the Facility Ratings Methodology and associated responses for three years. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

- 1.4.1 Facility Ratings Methodology
- 1.4.2 Superseded portions of its Facility Ratings Methodology that had been replaced, changed or revised within the past 12 months
- 1.4.3 Documented comments provided by a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Authority on its technical review of a Transmission Owner’s or Generator Owner’s Facility Ratings methodology, and the associated responses

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if any of the following conditions exists:

- 2.1.1 The Facility Ratings Methodology does not contain a statement that a Facility Rating shall equal the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- 2.1.2 The Facility Ratings Methodology does not address one of the required equipment types identified in FAC-008 R1.2.1.
- 2.1.3 No evidence of responses to a Reliability Coordinator’s, Transmission Operator, Transmission Planner, or Planning Authority’s comments on the Facility Ratings Methodology.

2.2. Level 2: The Facility Ratings Methodology is missing the assumptions used to determine Facility Ratings or does not address two of the required equipment types identified in FAC-008 R1.2.1.

2.3. Level 3: The Facility Ratings Methodology does not address three of the required equipment types identified in FAC-008-1 R1.2.1.

2.4. Level 4: The Facility Ratings Methodology does not address both Normal and Emergency Ratings or the Facility Ratings Methodology was not made available for inspection within 15 business days of receipt of a request.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	01/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time	01/20/05

Standard FAC-008-4X — Facility Ratings Methodology

		Frame” and “twelve” to “12” in item D, 1.2.	
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R1.2.1 to include the Generator Interconnection Facility</u>	<u>Addition</u>

A. Introduction

1. **Title:** Establish and Communicate Facility Ratings
2. **Number:** FAC-009-X1
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
 - 4.1. Transmission Owner
 - 4.2. Generator Owner
5. **Effective Date:** ~~October 7, 2006~~TBD

B. Requirements

- R1. The Transmission Owner and Generator Owner shall each establish Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are consistent with the associated Facility Ratings Methodology.
- R2. The Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities, including the Generator Interconnection Facility, that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

C. Measures

- M1. The Transmission Owner and Generator Owner shall each be able to demonstrate that it developed its Facility Ratings consistent with its Facility Ratings Methodology.
 - M1.1 The Transmission Owner's and Generator Owner's Facility Ratings shall each include ratings for its solely and jointly owned Facilities including new Facilities, existing Facilities, modifications to existing Facilities and re-ratings of existing Facilities.
- M2. The Transmission Owner and Generator Owner shall each have evidence that it provided its Facility Ratings to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities.

D. Compliance

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

Regional Reliability Organization
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

Each Transmission Owner and Generator Owner shall self-certify its compliance to the Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January–December) and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last finding of non-compliance.

1.3. Data Retention

The Transmission Owner and Generator Owner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant.

The Compliance Monitor shall retain audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner and Generator Owner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

- 1.4.1 Facility Ratings Methodology
- 1.4.2 Facility Ratings
- 1.4.3 Evidence that Facility Ratings were distributed
- 1.4.4 Distribution schedules provided by entities that requested Facility Ratings

2. Levels of Non-Compliance

- 2.1. **Level 1:** Not all requested Facility Ratings associated with existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.
- 2.2. **Level 2:** Not all Facility Ratings associated with new Facilities, modifications to existing Facilities, and re-ratings of existing Facilities were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) in accordance with their respective schedules.
- 2.3. **Level 3:** Facility Ratings provided were not developed consistent with the Facility Ratings Methodology.
- 2.4. **Level 4:** No Facility Ratings were provided to the Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), or Transmission Operator(s) in accordance with their respective schedules.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
1	08/01/05	1. Lower cased the word “draft” and “drafting team” where appropriate. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R2 to include the Generator Interconnection Facility</u>	<u>Addition</u>

A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-~~X2~~
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
 - 4.3. Transmission Operators.
 - 4.4. Transmission Service Providers.
 - 4.5. Generator Operators.
 - 4.6. Load-Serving Entities.
 - 4.7. Purchasing-Selling Entities.
5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
 - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems) and system loading.
 - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.4. System real and reactive reserves (actual versus required).
 - R1.5. Capacity and energy adequacy conditions.
 - R1.6. Current ACE for all its Balancing Authorities.
 - R1.7. Current local or Transmission Loading Relief procedures in effect.
 - R1.8. Planned generation dispatches.
 - R1.9. Planned transmission or generation outages.
 - R1.10. Contingency events.
- R2. Each Reliability Coordinator shall be aware of all Interchange Transactions that wheel through, source, or sink in its Reliability Coordinator Area, and make that Interchange Transaction information available to all Reliability Coordinators in the Interconnection.

- R3.** As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the Reliability Coordinator shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.
- R4.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R5.** Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.
- R6.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R7.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R8.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R9.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages, [including the Generator Interconnection Facility](#), with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R10.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R11.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of

the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

~~R13.~~ The Generator Operator shall immediately inform the Transmission Operator of the status of the Special Protection System, including any degradation or potential failure to operate as expected for SPS relay or control equipment under its control.

~~R13.~~~~R14.~~ Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

~~R14.~~~~R15.~~ Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

~~R15.~~~~R16.~~ Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

~~R16.~~~~R17.~~ Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.

~~R17.~~~~R18.~~ When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

M1. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.

M2. The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Historical Tag Archive information, Interchange Transaction records,

computer printouts, voice recordings or transcripts of voice recordings or equivalent evidence that will be used to confirm that it was aware of and made Interchange Transaction information available to all other Reliability Coordinators, as specified in Requirement 2.

- M3.** If a potential or actual IROL violation occurs, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, system event logs, operator action notes or equivalent evidence that will be used to determine if it initiated control actions or emergency procedures to relieve that IROL violation within 30 minutes. (Requirement 3 Part 2 and Requirement 5)
- M4.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2 and Requirement 10)
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 6)
- M6.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 7.
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 8 Part 1.
- M8.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 8 Part 2)
- M9.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 9 Part 1)
- M10.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings

or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 11 Part 1)

- M11.** If a Special Protection System is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Special Protection System on inter-area flows. (Requirement 12)
- M12.** If there is an instance where there is a disagreement on a derived limit, the Reliability Coordinator, Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Part 2 of Requirement 13)
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it provided SOL and IROL information to Transmission Service Providers within its Reliability Coordinator Area. (Requirement 14, Part 1)
- M14.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)
- M15.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 15 Part 1.
- M16.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 15 Part 2.
- M17.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 15 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 11, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–10 and Measure 13, and Measures 15 through 16, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 8, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 12, the Reliability Coordinator, Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 14, the Transmission Service Provider shall keep 90 days of historical data (evidence).

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.

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for a Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider**
 - 2.1. **Level 1:** Not applicable.
 - 2.2. **Level 2:** Not applicable.
 - 2.3. **Level 3:** Not applicable.
 - 2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
 - 2.4.1 Did not follow the Reliability Coordinator's directives in accordance with R8 Part 2).
 - 2.4.2 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)
3. **Levels of Non-Compliance for a Reliability Coordinator:**
 - 3.1. **Level 1:** Not applicable.
 - 3.2. **Level 2:** Did not make Interchange Transaction information available to all other Reliability Coordinators in the Interconnection. (Requirement 2)
 - 3.3. **Level 3:** There shall be a separate Level 3 non-compliance, for every one of the following requirements that is in violation:
 - 3.3.1 Did not communicate to each of its Balancing Authorities and Transmission Operators to make them aware of GMD forecast information or did not assist in the development of any required response plans to a predicted GMD. (Requirement 6)
 - 3.3.2 Did not disseminate information within its Reliability Coordinator Area. (Requirement 7)
 - 3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
 - 3.4.1 Does not meet one or more of the requirements as specified in requirement 1 (Requirements 1.1 through R1.9)
 - 3.4.2 Did not make Interchange Transaction information available to all other Reliability Coordinators. (Requirement 2)
 - 3.4.3 Did not initiate control actions or emergency procedures to relieve an IROL violation without delay, and no longer than 30 minutes. (Requirement 3 Part 2 and Requirement 5)
 - 3.4.4 Did not direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 4 Part 2)
 - 3.4.5 Did not monitor the system frequency or each of its Balancing Authorities performance or did not direct rebalancing to return to DCS and CPS compliance. (Requirement 8 Part 1)
 - 3.4.6 Did not coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. (Requirement 9)

- 3.4.7 When it identified a source of large Area Control Errors, it did not initiate corrective actions with the appropriate Balancing Authority if the problem was inside its Reliability Coordinator Area. (Requirement 11 part 1)
- 3.4.8 Did not provide evidence that it was aware of the impact of the operation of a Special Protection System on inter-area flows. (Requirement 12)
- 3.4.9 Did not operate to the most limiting parameter when a difference in derived limits existed. (Requirement 13 Part 2)
- 3.4.10 Did not provide Transmission Service Providers with SOLs or IROLs (within the Reliability Coordinator’s wide-area view) (Requirement 14 Part 1)
- 3.4.11 Did not issue alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area. (Requirement 15)

4. Levels of Non-Compliance for a Transmission Service Provider

- 4.1. **Level 1:** Not applicable.
- 4.2. **Level 2:** Not applicable.
- 4.3. **Level 3:** Not applicable.
- 4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
 - 4.4.1 Did not operate to the most limiting parameter when a difference in derived limits existed. (R13 Part 2)
 - 4.4.2 Did not respect the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 14 Part 2)

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	February 2, 2006	Approved by Board of Trustees	Revised
2	August 31, 2006	Added three items that were inadvertently left out to “Applicability” section: 4.5 Generator Operators. 4.6 Load-Serving Entities. 4.7 Purchasing-Selling Entities	Errata
2	November 1, 2006	Approved by Board of Trustees	Revised
2	June 26, 2007	Approved by FERC:	Revised

Standard IRO-005-X2 — Reliability Coordination — Current Day Operations

		Missing Measures and Compliance Elements	
<u>X</u>	<u>TBD</u>	<u>Modified R9 to include the Generator Interconnection Facility.</u> <u>Added a new Requirement R13</u>	<u>Addition</u>

A. Introduction

1. **Title:** Steady-State Data for Modeling and Simulation of the Interconnected Transmission System
2. **Number:** MOD-010-~~X0~~
3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems.
4. **Applicability:**
 - 4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-011-0_R1
 - 4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-011-0_R1
 - 4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-011-0_R1
 - 4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-011-0_R1
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. The Transmission Owners, Transmission Planners Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners -(specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R1.
- R2. The Transmission Owners, Transmission Planners, Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners -(specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).

C. Measures

- M1. The Transmission Owner, Transmission Planner, Generator Owner, and Resource Planner, (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall have evidence that it provided equipment characteristics, system data, and Interchange Schedules for steady-state modeling and simulation to the Regional Reliability Organizations and NERC as specified in Standard MOD-010-0_R1 and MOD-010-0_R2.

D. Compliance

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

Compliance Monitor: Regional Reliability Organizations.
 - 1.2. **Compliance Monitoring Period and Reset Timeframe**

As specified within the applicable reporting procedures (Reliability Standard MOD-011-0_R2-M1). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Steady-state data was provided, but was incomplete in one of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.2. Level 2: Not applicable.

2.3. Level 3: Steady-state data was provided, but was incomplete in two or more of the seven areas identified in Reliability Standard MOD-011-0_R1.

2.4. Level 4: Steady-state data was not provided.

E. Regional Differences

~~+~~None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R2 to include plant and Generator Interconnection Facility</u>	<u>Addition</u>

A. Introduction

1. **Title:** Dynamics Data for Modeling and Simulation of the Interconnected Transmission System.
2. **Number:** MOD-012-~~X0~~
3. **Purpose:** To establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the interconnected transmission systems.
4. **Applicability:**
 - 4.1. Transmission Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
 - 4.2. Transmission Planners specified in the data requirements and reporting procedures of MOD-013-0_R1
 - 4.3. Generator Owners specified in the data requirements and reporting procedures of MOD-013-0_R1
 - 4.4. Resource Planners specified in the data requirements and reporting procedures of MOD-013-0_R1
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. The Transmission Owners, Transmission Planners, Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R1.
- R2. The Transmission Owners, Transmission Planners, Generator Owners ([for plant and Generator Interconnection Facility](#)), and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R1. If no schedule exists, then these entities shall provide data on request (30 calendar days).

C. Measures

- M1. The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R1) shall each have evidence that it provided equipment characteristics and system data for dynamics system modeling and simulation in accordance with Reliability Standard MOD-012-0_R1 and Reliability Standard MOD-012-0_R2.

D. Compliance

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

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

As specified within the applicable reporting procedures (Reliability Standard MOD-013-0). If no schedule exists, then on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Dynamics data was provided, but was incomplete in one of the four areas identified in Reliability Standard MOD-013-0_R1.

2.2. Level 2: Not Applicable.

2.3. Level 3: Dynamics data was provided, but was incomplete in two or more of the four areas identified in Reliability Standard MOD-013-0_R1.

2.4. Level 4: Dynamics data was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	September 16, 2005	Changed references to MOD-013-0 R4 to MOD-013-0 R1 in Applicability, Requirements, and Measures (4 in all).	Errata
X	TBD	Modified R1 and R2 to include plant and Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** Operating Personnel Responsibility and Authority
2. **Number:** PER-001-~~X0~~
3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Generator Operators.
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
- R2. Each Generator Operator shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Generation Facility and Generation Interconnection Facility, and the responsibility and authority to follow the directives of reliability authorities including the Transmission Operator and Balancing Authority.

C. Measures

- M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:
 - M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.
 - M1.2 The current job description is readily accessible in the control room environment to all operating personnel.
 - M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.
 - M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

- 2.1. Level 1:** The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.
- 2.2. Level 2:** The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.
- 2.3. Level 3:** The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.
- 2.4. Level 4:** The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

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
X	TBD	Added new Requirement R2 Added Generator Operators to the Applicability Section	Addition

A. Introduction

1. **Title:** Operating Personnel Training
2. **Number:** PER-002-~~X0~~
3. **Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.
4. **Applicability**
 - 4.1. Balancing Authority.
 - 4.2. Transmission Operator.
 - 4.3. Generator Operator.
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. Each Transmission Operator, Generator Operator, and Balancing Authority shall be staffed with adequately trained operating personnel.
- R2. Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:
 - R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.
 - R2.2. Positions directly responsible for complying with NERC standards.
- R3. Each Generator Operator shall implement an initial and continuing training program for all operating personnel that are responsible for operating the Generator Interconnection Facility that verifies the personnel's ability and understanding to operate the equipment in a reliable manner.
- ~~R3~~R4. _____ For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:
 - ~~R3.1~~R4.1. _____ A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.
 - ~~R3.2~~R4.2. _____ The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.
 - ~~R3.3~~R4.3. _____ The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.
 - ~~R3.4~~R4.4. _____ Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.
- ~~R4~~R5. _____ For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training

and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

C. Measures

- M1. The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata
<u>X</u>	<u>TBD</u>	<u>Modified R1 and the Applicability Section to include Generator Operator</u> <u>Added new Requirement R3</u>	<u>Addition</u>

Standard PER-002-~~X0~~ — Operating Personnel Training

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A. Introduction

1. **Title:** System Protection Coordination

2. **Number:** PRC-001-~~X1~~

3. **Purpose:**

To ensure system protection is coordinated among operating entities.

4. **Applicability**

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area, [including those for the Generator Interconnection Facility](#).

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures, [including those for the Generator Interconnection Facility](#), as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes, [including those for the Generator Interconnection Facility](#), as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes, [including those for the Generator Interconnection Facility](#), with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

- R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions, [including those for the Generator Interconnection Facility](#), that could require changes in the protection systems of others:
- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions, [including those for the Generator Interconnection Facility](#), that could require changes in the Transmission Operator's protection systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

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.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

- 2.1. Level 1:** Not applicable.
- 2.2. Level 2:** Not applicable.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

- 3.1. Level 1:** Not applicable.
- 3.2. Level 2:** Not applicable.
- 3.3. Level 3:** Not applicable.

3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. **Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2:** Not applicable.

4.3. **Level 3:** Not applicable.

4.4. **Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

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
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
X	TBD	Modified R1, R2, R3, R3.1, R5, and R5.1 to include the Generator Interconnection Facility.	Addition

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-~~X1~~
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
 - 4.1. Transmission Owner.
 - 4.2. Distribution Provider that owns a transmission Protection System.
 - 4.3. Generator Owner.
5. **Effective Date:** ~~August 1, 2006~~ TBD

B. Requirements

- R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.
- R2. The Generator Owner shall analyze its generator Protection System Misoperations, including those for the Generator Interconnection Facility, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
- R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

- M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.
- M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
- M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

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

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

- 2.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.
- 2.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.
- 2.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.
- 2.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

- 3.1. Level 1:** Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.
- 3.2. Level 2:** Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.
- 3.3. Level 3:** Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.
- 3.4. Level 4:** Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
<u>X</u>	<u>TBD</u>	<u>Modified R2 to include the Generator Interconnection Facility</u>	<u>Addition</u>

A. Introduction

1. **Title:** **Transmission and Generation Protection System Maintenance and Testing**
2. **Number:** PRC-005-~~X1~~
3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.
4. **Applicability**
 - 4.1. Transmission Owner.
 - 4.2. Generator Owner.
 - 4.3. Distribution Provider that owns a transmission Protection System.
5. **Effective Date:** ~~May 1, 2006~~

B. Requirements

- R1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, [including those for the Generator Interconnection Facility](#), shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
 - R1.1. Maintenance and testing intervals and their basis.
 - R1.2. Summary of maintenance and testing procedures.
- R2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, [including those for the Generator Interconnection Facility](#) shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
 - R2.1. Evidence Protection System devices were maintained and tested within the defined intervals.
 - R2.2. Date each Protection System device was last tested/maintained.

C. Measures

- M1. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
- M2. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System that affects the reliability of the BES, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System, shall retain evidence of the implementation of its Protection System maintenance and testing program for three years.

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

1.4. Additional Compliance Information

The Transmission Owner and any Distribution Provider that owns a transmission Protection System and the Generator Owner that owns a generation Protection System, shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

- 2.1. Level 1:** Documentation of the maintenance and testing program provided was incomplete as required in R1, but records indicate maintenance and testing did occur within the identified intervals for the portions of the program that were documented.
- 2.2. Level 2:** Documentation of the maintenance and testing program provided was complete as required in R1, but records indicate that maintenance and testing did not occur within the defined intervals.
- 2.3. Level 3:** Documentation of the maintenance and testing program provided was incomplete, and records indicate implementation of the documented portions of the maintenance and testing program did not occur within the identified intervals.
- 2.4. Level 4:** Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ul style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—). 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” 	01/20/05

Standard PRC-005-~~X~~4 — Transmission and Generation Protection System Maintenance and Testing

		in item D, 1.2.	
<u>X</u>	<u>TBD</u>	<u>Modified R1 and R2 to include the Generator Interconnection Facility</u>	<u>Additions</u>

A. Introduction

1. **Title:** Reliability Responsibilities and Authorities

2. **Number:** TOP-001-X1

3. **Purpose:**

To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. **Applicability**

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

4.4. Distribution Providers

4.5. Load Serving Entities

5. **Effective Date:** ~~January 1, 2007~~ TBD

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

- R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.
- R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities, [including the Generator Interconnection Facility](#), from service if removing those facilities would burden neighboring systems unless:
- ~~1.~~[R7.1.](#) For a generator outage, [including the Generator Interconnection Facility](#), the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
- ~~2.~~[R7.2.](#) For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
- ~~3.~~[R7.3.](#) When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.
- R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.
- [R9. The Generator Operator, in accord with the expectations defined by the Transmission Operator, shall coordinate the operation of its Generator Interconnection Facility with the Transmission Operator to whom it interconnects in order to preserve Interconnection reliability with respect to the following:](#)
- [Switching elements](#)
 - [Outage planning](#)
 - [Real-time or anticipated emergency conditions](#)
 - [Other conditions mutually agreed upon by the Generator Operator and Transmission Operator](#)
- [R10. The Transmission Operator shall have decision-making authority over operation of the Generator Interconnection Operational Interface at all times in order to preserve Interconnection reliability.](#)

~~—The Generator Operator shall take the action it deems appropriate to remove from service the Generator Interconnection Facilities when safety is jeopardized or equipment damage is imminent.~~

~~—The Generator Operator shall notify the Transmission Operator as soon as practical of the actions taken and the reasons therein.~~

C. Measures

- M1.** Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.
- M2.** If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)
- M3.** Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)
- M4.** Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)
- M5.** The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected

Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

- M6.** The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)
- M7.** The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

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 supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

- 3.4.1 Does not have the documented authority to act as specified in R1.
- 3.4.2 Does not have evidence it acted with the authority specified in R1.
- 3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.
- 3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.
- 3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.
- 3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.
- 3.4.7 Did not render emergency assistance to others as requested, as specified in R6.
- 3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

- 4.1. **Level 1:** Not applicable.
- 4.2. **Level 2:** Not applicable.
- 4.3. **Level 3:** Not applicable.
- 4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
 - 4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.
 - 4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.
 - 4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

- 5.1. **Level 1:** Not applicable.
- 5.2. **Level 2:** Not applicable.
- 5.3. **Level 3:** Not applicable

5.4. **Level 4:** Did not comply with a Transmission Operator’s reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

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
<u>X</u>	<u>TBD</u>	<u>Modified R7 and R7.1 to include the Generator Interconnection Facility</u> <u>Added new Requirements R9 and R10, and R11.</u>	<u>Addition</u>

A. Introduction

1. **Title:** Normal Operations Planning
2. **Number:** TOP-002-~~X~~2
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
 - 4.1. Balancing Authority.
 - 4.2. Transmission Operator.
 - 4.3. Generator Operator.
 - 4.4. Load Serving Entity.
 - 4.5. Transmission Service Provider.
5. **Effective Date:** ~~January 1, 2007~~TBD
Six months after effective date of VAR-001-1.

B. Requirements

- R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.
- R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.
- R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations, including for the Generator Interconnection Facility, with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
- R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.
- R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

- R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
- R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
- R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.
- R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.
- R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
- R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.
- R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.
- R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.
- R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:
 - R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)
 - R14.1. **Changes in real output capabilities. (Effective August 1, 2007)**
 - R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)
 - R14.2. Changes in Generator Interconnection Facility Status
- R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
- R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator

and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network [and for the Generator Interconnection Facility](#).

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

- M7.** Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)
- M8.** Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)
- M9.** Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement 16)
- M10.** Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

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 supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

- 3.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
 - 3.2. **Level 2:** Not applicable.
 - 3.3. **Level 3:** One or more of Bulk Electric System studies were not made available as specified in R11.
 - 3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
 - 3.4.1 Did not maintain an updated set of current-day plans as specified in R1.
 - 3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.
 - 3.4.3 Studies not updated to reflect current system conditions as specified in R11.
 - 3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.
4. **Levels of Non-Compliance for Generator Operators:**
- 4.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
 - 4.2. **Level 2:** Not applicable.
 - 4.3. **Level 3:** Not applicable.
 - 4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
 - 4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.
 - 4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.
 - 4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.
5. **Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:**
- 5.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
 - 5.2. **Level 2:** Not applicable.
 - 5.3. **Level 3:** Not applicable.
 - 5.4. **Level 4:** Not applicable.

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	June 14, 2007	Fixed typo in R11., (subject to ...)	Errata
<u>X</u>	<u>TBD</u>	<u>Modified R3 and R18 to include the Generator Interconnection Facility and added Requirement R14.3.</u>	<u>Addition</u>

A. Introduction

1. **Title:** **Planned Outage Coordination**
2. **Number:** TOP-003-~~X0~~
3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
4. **Applicability**
 - 4.1. Generator Operators.
 - 4.2. Transmission Operators.
 - 4.3. Balancing Authorities.
 - 4.4. Reliability Coordinators.
5. **Effective Date:** ~~April 1, 2005~~TBD

B. Requirements

- R1. Generator Operators and Transmission Operators shall provide planned outage information, including information for the Generator Interconnection Facility.
 - R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW) or the Generator Interconnection Facility. The Transmission Operator shall establish the outage reporting requirements.
 - R1.2. Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.
 - R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
- R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.
- R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
- R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

- M1. Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

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
X	TBD	Modified R1 and R1.1 to include the Generator Interconnection Facility	Addition

A. Introduction

1. **Title:** Transmission Operations
2. **Number:** TOP-004-~~X2~~
3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
4. **Applicability:**
 - 4.1. Transmission Operators
5. **Proposed Effective Date:** ~~Twelve months after BOT adoption of FAC-014~~[TBD](#).

B. Requirements

- R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
- R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
- R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.
- R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.
- R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.
- R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:
 - R6.1. Monitoring and controlling voltage levels and real and reactive power flows.
 - R6.2. Switching transmission elements.
 - R6.3. Planned outages of transmission elements.
 - R6.4. Responding to IROL and SOL violations.
- [R7. The Generator Operator shall operate its Generator Interconnection Facility within its applicable ratings.](#)

C. Measures

- M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

- M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

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 supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. **Level 1:** Not applicable.

2.2. **Level 2:** Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. **Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

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	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata
<u>X</u>	<u>TBD</u>	<u>Added Requirement R7</u>	<u>Addition</u>

A. Introduction

1. **Title:** Response to Transmission Limit Violations
2. **Number:** TOP-008-X1
3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Generator Operators.
5. **Effective Date:** ~~January 1, 2007~~TBD

B. Requirements

- R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.
- R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.
- R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
- R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.
- R5. The Generator Operator shall disconnect the Generator Interconnection Facility when safety is jeopardized or if the overload or abnormal voltage or reactive condition persists and generating equipment or the Generator Interconnection Facility is endangered. In doing so, the Generator Operator shall notify its Transmission Operator and Balancing Authority impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

C. Measures

- M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

- M2.** The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1
- M3.** The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)
- M4.** The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents, copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)
- M5.** The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

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

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

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 data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard TOP-008-X4 — Response to Transmission Limit Violations

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
<u>X</u>	<u>TBD</u>	<u>Added new Requirement R5</u>	<u>Addition</u>

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-~~X~~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. Purchasing-Selling Entities.
5. **Effective Date:** ~~Six months after BOT adoption.~~^{TBD}

B. Requirements

- R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.
- R2.** Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.
- R3.** The Transmission Operator shall specify criteria that exempts generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.
 - R3.1.** Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.
 - R3.2.** For each generator that is on this exemption list, the Transmission Operator shall notify the associated Generator Owner.
- R4.** Each Transmission Operator shall specify a voltage or Reactive Power schedule ¹ at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).
- R5.** Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.
- R6.** The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.
 - R6.1.** When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.
- R7.** The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.

¹ The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

- R8.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line, [Generator Interconnection Facility](#), and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.
- R9.** Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.
 - R9.1.** Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.
- R10.** Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.
- R11.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes, 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.
- R12.** The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

- M1.** The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.
- M2.** The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.
- M3.** The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.
- M4.** 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 Requirement 11.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

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

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

- 2.1. Level 1:** No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2
- 2.2. Level 2:** There shall be a level two non-compliance if either of the following conditions exists:
 - 2.2.1** No evidence to show that directives were issued in accordance with R6.1.
 - 2.2.2** No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit’s step-up transformer tap in accordance with R11.
- 2.3. Level 3:** There shall be a level three non-compliance if either of the following conditions exists:
 - 2.3.1** Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.
- 2.4. Level 4:** No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	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
<u>X</u>	<u>TBD</u>	<u>Modified R8 to include Generator Interconnection Facility</u>	<u>Addition</u>

A. Introduction

1. **Title:** Generator Operation for Maintaining Network Voltage Schedules
2. **Number:** VAR-002-~~X~~1a
3. **Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
4. **Applicability**
 - 4.1. Generator Operator.
 - 4.2. Generator Owner.
5. **Effective Date:** ~~May 13, 2009~~TBD

B. Requirements

- R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.
- R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings¹) as directed by the Transmission Operator.
 - R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.
 - R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.
- R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:
 - R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.
 - R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control, including the Generator Interconnection Facility, and the expected duration of the change in status or capability.
- R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.
 - R4.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
 - R4.1.1. Tap settings.
 - R4.1.2. Available fixed tap ranges.

¹ When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

R4.1.3. Impedance data.

R4.1.4. The +/- voltage range with step-change in % for load-tap changing transformers.

R5. 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.

R5.1. If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

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 as specified in Requirement 1.

M2. The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.

M3. The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.

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 Requirements 4.1.1 through 4.1.4

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.

M7. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

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

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in , R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission as identified in R1, R3.1,R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.

2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

3.1.1 Level One: Not applicable.

3.1.2 Level Two: Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.

3.1.3 Level Three: No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage

3.1.4 Level Four: Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

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E. Regional Differences

None identified.

F. Associated Documents

1. Appendix 1 – Interpretation of Requirements R1 and R2 (August 1, 2007).

Version History

Version	Date	Action	Change Tracking
1	May 15, 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	December 19, 2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	January 16, 2007	In Section A.2., Added “a” to end of standard number. Section F: added “1.”; and added date.	Errata
1.1a	October 29, 2008	BOT adopted errata changes; updated version number to “1.1a”	Errata
1.1a	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
<u>X</u>	<u>TBD</u>	<u>Modified R3.2 to include the Generator Interconnection Facility</u>	<u>Addition</u>

Appendix 1

Interpretation of Requirements R1 and R2

Request:

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (*automatic voltage regulator in service and controlling voltage*) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage *or Reactive Power output* as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rationale is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rationale stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.
- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation:

1. First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

Interpretation: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.