Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 321, 330, 335, 1232.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

DEFINITIONS OF TERMS USED IN STANDARD

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Demand-Side Management (DSM): ~~The term for all a~~Activities ~~or programs~~ undertaken by end-use customers, Load-Serving Entitiesy~~y~~, or ~~its customers~~their agents or representatives to influence the amount or timing of electricity they use without violating Reliability Standards in order to provide the one or more services traditionally provided by generation resources. In order to do so, loads must have the same response characteristics (but not necessarily mechanical or physical implementation) of the resources it is replacing.

~~**Spinning Reserve:** Unloaded generation that is synchronized and ready to serve additional demand.~~

Operating Reserve – Spinning: The portion of Operating Reserve consisting of:

- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or
- Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Operating Reserve –Supplemental: The portion of Operating Reserve consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or
- Demand Side Management Resources or other devices with control capability to adequately respond within the time necessary to provide the service; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

A. Introduction

1. **Title:** **Disturbance Control Performance**

2. **Number:** BAL-002-~~0~~1

3. **Purpose:**

The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. **Applicability:**

4.1. Balancing Authorities

4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

4.3. Regional Reliability Organizations

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption. ~~April 1, 2005~~

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable ~~load~~ resources, Demand Side Management (DSM), or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the ~~NERC Operating Committee~~ERO.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

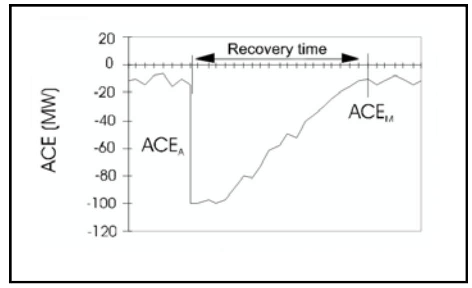
R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the ~~NERC Operating Committee~~ERO.

C. Measures

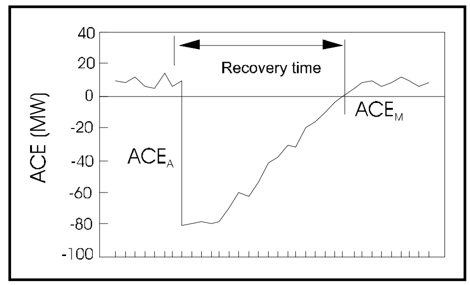
M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:



if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$
then

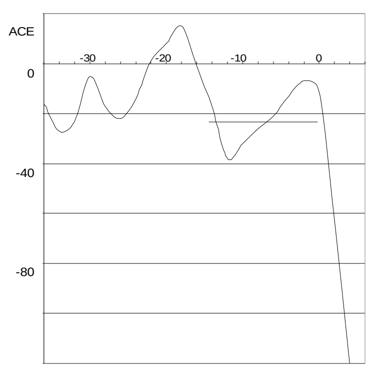
$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional ~~Reliability Organization~~Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

~~1.4.~~1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation.

The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

~~**2.1. Level 1:** Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.~~

~~**2.2. Level 2:** Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.~~

~~**2.3. Level 3:** Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.~~

~~**Level 4:** Value of average percent recovery for the quarter is less than 85%.~~

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	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraphs 321, 330, 335, and 1232.	Revised.

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Automatic Generation Control (AGC): ~~Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.~~See ARC.

Automatic Resource Control (ARC): Automatic adjustment of resources in a Balancing Authority Area to maintain the Balancing Authority's interchange schedule plus Frequency Bias. ARC may also accommodate automatic inadvertent payback and time error correction.

Regulating Reserve: ~~An amount of r~~Reserve that is responsive to Automatic ~~Generation~~ Resource Control, which is sufficient to provide normal regulating margin. Regulating Reserve may be comprised of generation, controllable load resources, Demand Side Management (DSM), or other resources that have comparable response characteristics.

A. Introduction

1. **Title:** **Automatic ~~Generation~~ Resource Control**

2. **Number:** BAL-005-~~0.1b~~1

3. **Purpose:**

   This standard establishes requirements for Balancing Authority Automatic ~~Generation~~ Resource Control (~~AGC~~ARC) 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. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption. ~~May 13, 2009~~

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 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~~ ARC 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 either the supplying Balancing Authority no longer be able to provide this service or the service is no longer deliverable due to transmission constraints impacting non-firm transmission service.

R6. The Balancing Authority's ~~AGC~~ ARC 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~~ ARC continuously unless such operation adversely impacts the reliability of the Interconnection. If ~~AGC~~ ARC 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~~ ARC 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~~verify against a common reference the calibration of its ~~time error and~~ frequency devices that provide input into the reporting or compliance ACE equation or provide real-time error or frequency information to the system operator.~~against a common reference.~~

R17.1. ~~The~~ If the calibration of a frequency device described above is found to not be accurate within +/- 0.001 Hz, the Balancing Authority shall within 60 calendar days ~~adhere to the minimum values for measuring devices as listed below~~either:

- Calibrate the device to within +/- 0.001 Hz, or
- Replace the device

~~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~~Enforcement Authority

Balancing Authorities shall be prepared to supply data to ~~NERC~~NERC and -their Regional Entity in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional ~~Reliability Organization~~Entity 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~~Entity 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 applicable. ~~Not specified.~~

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. 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.~~None.

2. ~~Levels of Non-Compliance~~Violation Severity Levels (changes only)

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	N/A	N/A	N/A	The Balancing Authority failed to maintain Regulating Reserve that can be controlled by ~~AGC~~ ARC to meet Control Performance Standard.
R7	N/A	N/A	N/A	The Balancing Authority failed to operate ARGC continuously when there were no adverse impacts. OR If its ~~AGC~~ ARC was inoperative the Balancing Authority failed to use manual control to adjust generation to maintain the Net Scheduled Interchange.
R15	N/A	N/A	The Balancing Authority failed to periodically test backup power supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of ~~AGC~~ ARC and vital data recording equipment during loss of the normal power supply.	The Balancing Authority failed to provide adequate and reliable backup power supplies to ensure continuous operation of ~~AGC~~ ARC and vital data recording equipment during loss of the normal power supply.
R17	The Balancing authority identified a frequency device that was found to not be accurate within +/- 0.001 Hz, and within 60 calendar days neither calibrated the device to be within +/- 0.001 Hz nor replaced the device, but did take	The Balancing authority identified a frequency device that was found to not be accurate within +/- 0.001 Hz, and within 90 calendar days neither calibrated the device to be within +/- 0.001 Hz nor replaced the device, but did take	The Balancing authority identified a frequency device that was found to not be accurate within +/- 0.001 Hz, and within 120 calendar days neither calibrated the device to be within +/- 0.001 Hz nor replaced the device, but did take	The Balancing Authority failed to at least annually check ~~and calibrate~~ its ~~time error and~~ frequency devices against a common reference. OR The Balancing authority

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	such action in 90 calendar days or less.~~N/A~~	such action in 120 calendar days or less.~~N/A~~	such action in 150 calendar days or less.~~N/A~~	identified a frequency device that was found to not be accurate within +/- 0.001 Hz, and within 150 days neither calibrated the device to be within +/- 0.001 Hz nor replaced the device.

~~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
1	TBD	Modified to address Order No. 693 Directives contained in paragraphs 404, 415, and 420.	Revised.

~~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*~~

~~**BAL-005-1**~~

~~**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.~~

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 565 and 582.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-~~1~~2

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. **(Proposed) Effective Dates:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

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. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity, including emergencies that arise due to a lack of transmission capability and those whose mitigation plans are hindered by a lack of transmission capability.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R2.4. Develop, maintain, and implement a set of plans for system restoration.

R3. 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:

R3.1. Communications protocols to be used during emergencies.

R3.2. 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.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall consider, and if appropriate include, the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

R5. 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.

R6. 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:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. 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.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. 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~~Enforcement Authority

~~Regional Reliability Organization~~Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

~~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.~~Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

Current plan available at all times.

~~1.4.~~1.5. Additional Compliance Information

~~Not specified.~~None.

2. Violation Severity Levels (changes only):

Requirement	Lower	Moderate	High	
R4	The Responsible Entity cannot demonstrate that it considered or addressed one of the appropriate elements listed in the attachment.~~Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.~~	The Responsible Entity cannot demonstrate that it considered or addressed two of the appropriate elements listed in the attachment.~~Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.~~	The Responsible Entity cannot demonstrate that it considered or addressed three of the appropriate elements listed in the attachment.~~Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.~~	The Responsible Entity cannot demonstrate that it considered or addressed four or more of the appropriate elements listed in the attachment.~~Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components~~

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		Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 565 and 582.	Revised.

Attachment 1-EOP-001-0

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.

Standard Development Roadmap

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Modified to address Order No. 693 Directives contained in paragraphs 573 and 582.

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None.

Introduction

1. **Title**: **Capacity and Energy Emergencies**
2. **Number**: EOP-002-~~2.1~~3
3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   - **4.1.** Balancing Authorities.
   - **4.2.** Reliability Coordinators.
   - **4.3.** Load-Serving Entities.
5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.~~May 13, 2009~~

A. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, ~~implement~~ take one or more actions as described in its capacity and energy emergency plan, ~~when required and as appropriate~~, to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.

R6.2. Deploying all available operating reserve.

R6.3. Deploying all available Demand-Side Management options,

~~R6.3.~~R6.4. Interrupting interruptible load and exports.

~~R6.4.~~R6.5. Requesting emergency assistance from other Balancing Authorities.

~~R6.5.~~R6.6. Declaring an Energy Emergency through its Reliability Coordinator; and

~~R6.6.~~R6.7. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R6.8. Deploying any available alternative technologies not included above that are designed to supply energy to or reduce demand on the Bulk Electric System.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

B. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements ~~its~~ one or more actions described in its Capacity and Energy Emergency plan, that entity 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, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it 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 met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took action to limit its use of Interconnection assistance and that for any unilateral adjustment of generation, it has justification for those adjustments other than attempting to return Interconnection frequency to normal. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

~~M7.~~M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, 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, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.

~~M8.~~M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration

Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

Regional ~~Reliability Organizations shall be responsible for compliance monitoring.~~Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable. ~~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. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, ~~4~~ 8 and ~~5~~ 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

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 for a Reliability Coordinator:~~Violation Severity Levels (changes only)

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	The Balancing Authority was not able to comply with the Control Performance and Disturbance Control Standards and failed to immediately implement one (1) of the sub-requirements R6.1, R6.2, R6.3, R6.4, R6.5, ~~or~~ R6.6, R6.7, or R6.8.	The Balancing Authority was not able to comply with the Control Performance and Disturbance Control Standards and failed to immediately implement more than one (1) of the sub-requirements R6.1, R6.2, R6.3, R6.4, R6.5 ~~or~~, R6.6~~.~~, R6.7, or R6.8. OR The Balancing Authority was not able to comply with the Control Performance and Disturbance Control Standards and did not immediately implement any remedies.

~~2.1. following requirements that is in violation:~~

~~2.2. Failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities when in an operating Capacity or Energy Emergency (R3).~~

2.1. ~~One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate (R2).~~

D. 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	September 19, 2006	Changes R7. to refer to "Requirement 6" instead of "Requirement 7"	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. "Applicability."	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted "4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to "2.1"	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 573 and 582.	Revised.

Attachment 1-EOP-002-2.1
Energy Emergency Alerts

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

    1.1. Situations for initiating alert. An Energy Emergency Alert may be initiated for the following reasons:

    - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
    - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency

Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 — Load management procedures in effect.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the

[1] For emergency, not economic, reasons.

Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 601 and 603.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

Introduction

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

2. **Number:** EOP-003-~~1~~2

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

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day othe first calendar quarter one year after Board of Trustees' adoption.~~January 1, 2007~~

A. 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~~with each of the following:

R3.1. Interconnected Transmission Operators and Balancing Authorities.

R3.2. Regional Entities within whose regions they operate.

R3.3. Reliability Coordinator(s) associated with overseeing the operations of the Balancing Authority or Transmission Operator.

~~**R2.1.**~~**R3.4.** Generator Owners within the Balancing Authority Area or Transmission Operator Area, as appropriate.

~~**R3.**~~**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.

~~**R4.**~~**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.

~~**R5.**~~**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.

~~R6.~~R7. The Transmission 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.

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.

R8. At least annually, each Transmission Operator and Balancing Authority shall test their load shedding plans through simulation. [*Violation Risk Factor: Low*[*Time Horizon: Long-term Planning, Operations Planning*]

R9. At least every two years, each Transmission Operator, Balancing Authority, Load Serving Entity, and Distribution Provider shall participate in a test of the applicable load shedding plans. Such test shall include 1) coordination between Load Serving Entities, Distribution Providers, and the initiator of the test, and 2) personnel deployment drills. [*Violation Risk Factor: Low* [*Time Horizon: Long-term Planning, Operations Planning*]

B. 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)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~Regional Entity.

1.2. Compliance Monitoring and Reset Time Frame

~~One or more of the following methods will be used to assess compliance~~Not Applicable.:

- ~~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. Compliance Monitoring and Enforcement Processes:

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

Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)

Periodic Audit (Conducted once every three years according to schedule.)

Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

~~1.3. Additional Reporting Requirement~~

~~No additional reporting required.~~

1.4. Data Retention

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

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

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

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

1.5. Additional Compliance Information

None.

2. Violation Severity Levels (changes only):

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R9				The responsible entity did not test their load shedding plans through simulation at least annually.
R10			The responsible entity did not participate in a test of the load shedding plans that included personnel deployment drills at least every two years.	The responsible entity did not participate in a test of the load shedding plans that included coordination between Load Serving Entities, Distribution Providers, and the initiator of the test at least every two years.

D. 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	TBD	Modified to address Order No. 693 Directives contained in paragraphs 601 and 603.	Revised.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 612 and 615.

Development Steps Completed:

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Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

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Definitions of Terms Used in Standard

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None.

Introduction

1. **Title:** **Disturbance Reporting**

2. **Number:** EOP-004-~~1~~2

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.

   ~~4.4.~~4.5. Distribution Providers

   ~~4.5.~~4.6. Load Serving Entities.

   ~~4.6.~~4.7. Regional Reliability Organizations.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.~~January 1, 2007~~

A. 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~~ Each Reliability Coordinator, Balancing Authority, and Transmission Operator, ~~Generator Operator or Load Serving Entity~~ shall promptly analyze Bulk Electric System disturbances on its system or facilities.

R3. Each Generator Operator, Distribution Provider, and Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities. [*Violation Risk Factor: Medium*] [*Time Horizon: Same Day Operations, Real Time Operations*]

R3.1. At a minimum, the responsible entity shall analyze the performance of their equipment and provide this information to its associated Reliability Coordinator, Balancing Authority, and Transmission Operator.

R4. A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report (as shown in Attachment 1) to its Regional Reliability Organization and NERC.

~~R1.1.~~R4.1. 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.

~~R1.2.~~R4.2. Applicable reporting forms are provided in Attachments 1-EOP-004 and 2-EOP-004.

~~R1.3.~~R4.3. 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.

~~R1.4.~~R4.4. 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.

~~R2.~~R5. 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.

~~R3.~~R6. 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.

B. 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)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~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.~~Regional Entity.

1.2. Compliance Monitoring and Reset Time Frame

~~One or more of the following methods will be used to assess compliance:~~Not applicable.

- ~~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. Compliance Monitoring and Enforcement Processes:

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

Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)

Periodic Audit (Conducted once every three years according to schedule.)

Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

~~1.3.~~1.4. 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 43)

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.~~1.5. Additional Compliance Information

See Attachments:

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

2. Violation Severity Levels (changes only)~~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.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The responsible entity failed to promptly analyze 5% or less of its disturbances on the BES.	The responsible entity failed to promptly analyze more than 5% up to (and including) 10% of its disturbances on the BES.	The responsible entity failed to promptly analyze more than 10% up to (and including) 15% of its disturbances on the BES.	The responsible entity failed to promptly analyze more than 15% of its disturbances on the BES.

D. 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
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
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 612 and 615.	Revised.

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 ±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. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	Yes ☐ No ☐	
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. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.		FIRM	INTERRUPTIBLE
	Demand tripped (MW):		
	Number of affected Customers:		

	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 ≤ 50% of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 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:	• 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.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraph 693.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

DEFINITIONS OF TERMS USED IN STANDARD

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

Introduction

1. **Title:** **Coordination of Plans For New Generation, Transmission, and End-User Facilities**

2. **Number:** FAC-002-~~0~~ 1

3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Transmission Owner

   4.3. Distribution Provider

   4.4. Load-Serving Entity

   4.5. Transmission Planner

   4.6. Planning Authority

5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.~~April 1, 2005~~

A. Requirements

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.

1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.

1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.

1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

B. Measures

M1. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.

M2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor: RRO~~Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

~~On request (within 30 calendar days)~~Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

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

Complaints

~~1.3.~~1.4. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

~~1.4.~~1.5. Additional Compliance Information

None

2. Violation Severity Levels (no changes)~~of Non-Compliance~~

~~**2.1. Level 1:** Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard FAC-002_R1.~~

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

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

~~**2.4. Level 4:** Assessments of the impacts of new facilities were not provided.~~

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of "Regional Reliability Organizations(s).	Errata
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 693.	Revised.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 1249, 1250, 1251, 1252, and 1255.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

Introduction

1. **Title:** **Aggregated Actual and Forecast Demands and Net Energy for Load**
2. **Number:** MOD-017-~~0.1~~1
3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessment to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
4. **Applicability:**
   4.1. Load-Serving Entity.
   4.2. Planning Authority.
   4.3. Resource Planner.
   4.4. Transmission Planner.
5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~May 13, 2009~~

A. Requirements

R1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-1_R1.

R1.1. Integrated hourly demands in megawatts (MW) for the prior year. For Loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year.

R1.2. Monthly and annual peak hour actual demands in MW and Net Energy for Load in gigawatthours (GWh) for the prior year. For Loads that vary based on temperature and/or humidity, coincident hourly temperature and humidity data for the prior year.

R1.3. Monthly peak hour forecast demands in MW and Net Energy for Load in GWh for the next two years.

R1.4. Annual Peak hour forecast demands (summer and winter) in MW and annual Net Energy for load in GWh for at least five years and up to ten years into the future, as requested.

R1.5. Day-ahead Hourly for each hour, Monthly peak hour, and Annual Peak hour load Forecast accuracy (expressed in terms of error divided by actual demand) as well as any biasing of each load forecast.

R2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review Load forecast variation for the previous year and, if necessary (e.g., if variation expressed in terms of error divided by actual demand is greater than 10%), modify load forecast assumptions to improve accuracy. [*Violation Risk Factor: Low*] [*Time Horizon: Operations Assessment*].

B. Measures

M1. Load-Serving Entity, Planning Authority, Transmission Planner and Resource Planner shall each provide evidence (such as e-mails, delivery confirmations, or other evidence) to its Compliance Monitor that it provided load data ~~per Standard MOD-017-0~~ R1.

M2. Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence (such as load data, change logs, or other evidence) that it annually reviewed Load forecast accuracy and, if necessary, modified load forecast assumptions to improve accuracy.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor:~~ Regional ~~Reliability Organization.~~Entity

1.2. Compliance Monitoring Period and Reset Time Frame

Annually or as specified in the documentation (Standard MOD-016-1_R1.)

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

None specified.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels (changes only)

~~Levels of Non-Compliance~~R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity failed to provide one (1) of the elements of information as specified in R1.1, R1.2, R1.3, R1.4 or R1.5~~4~~ on an annual basis.	The responsible entity failed to provide two (2) of the elements of information as specified in R1.1, R1.2, R1.3, R1.4 or R1.~~4~~ 5 on an annual basis.	The responsible entity failed to provide three (3) of the elements of information as specified in R1.1, R1.2, R1.3, R1.4 or R1.~~4~~ 5 on an annual basis.	The responsible entity failed to provide ~~all~~ four (4) or more of the elements of information as specified in R1.1, R1.2, R1.3, 1.4 or ~~and~~ R1.5~~4~~ on an annual basis.
R2			The responsible entity reviewed its Load forecast accuracy on an annual basis, but failed to make improvements to improve accuracy when such improvements were necessary (e.g., variation was greater than 10%).	The responsible entity failed to review its Load forecast accuracy on an annual basis.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 18, 2008	Revised R1. And D1.2. to reflect update in version from "MOD-016-0_R1" to MOD-016-1_R1."	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved — Updated Effective Date and Footer	Revised
1	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1249, 1250, 1251, 1252, and 1255.	New version.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 1276 and 1277.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
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Definitions of Terms Used in Standard

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None.

Introduction

1. **Title: Reporting of Interruptible Demands and Direct Control Load Management**

2. **Number:** MOD-019-~~0.1~~1

3. Purpose: To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity.

   4.2. Planning Authority.

   4.3. Transmission Planner.

   4.4. Resource Planner.

5. **(Proposed) Effective Date:** ~~May 13, 2009~~ The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

A. Requirements

R1. ~~The~~ Each Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall ~~each~~ provide the following data annually ~~its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions~~ to ~~NERC~~the ERO, the Regional ~~Reliability Organizations~~Entity, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation ~~in~~ required by Reliability Standard MOD-016-1_R1.

R1.1. Forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions

R1.2. Summer and winter peak Forecast variation for the previous year, expressed in terms of error divided by actual demand, as well as any biasing of each forecast.

R2. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall annually review Load forecast variation and, if necessary (e.g., if variation expressed in terms of error divided by actual demand is greater than 10%), modify load forecast assumptions to improve accuracy. [Violation Risk Factor: Low] [Time Horizon: Operations Assessment].

B. Measures

M1. The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide evidence to its Compliance Monitor that it provided forecasts of interruptible demands and DCLM data per Reliability Standard MOD-019-0_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Each~~ Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually or as specified in the documentation (Reliability Standard MOD-016-1_R1.)

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

None specified.

~~1.4.~~1.5. Additional Compliance Information

None.

2. Violation Severity Levels (changes only)~~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: Did not provide forecasts of interruptible Demands and DCLM data as required in Standard MOD-019-0_R1.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2			The responsible entity reviewed its Load forecast accuracy on an annual basis, but failed to make improvements to improve accuracy when such improvements were necessary (e.g., variation was greater than 10%).	The responsible entity failed to review its Load forecast accuracy on an annual basis.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
	February 8, 2005	Approved by BOT	Revised
0	July 24, 2007	Changed reference R1. and Dl.1.2. to "MOD-016-0_R1" to MOD-016-1_R1." (New version number.)	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1".	Errata
0.1	May 13, 2009	FERC Approved — Updated Effective Date and Footer	Revised
1	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1276 and 1277.	Revised.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraph 1287.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
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Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
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3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
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None.

Introduction

1. **Title:** **Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators**
2. **Number:** MOD-020-~~0~~ 1
3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed.
4. **Applicability:**
   - **4.1.** Load-Serving Entity
   - **4.2.** Transmission Planner
   - **4.3.** Resource Planner
5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption. ~~April 1, 2005~~

A. Requirements

R1. ~~The~~ Each Load-Serving Entity, Transmission Planner, and Resource Planner that receives a written request for its forecast amount of interruptible demands and Direct Control Load Management (DCLM) from a Transmission Operator, Balancing Authority, or Reliability Coordinator shall ~~each~~ make those forecasts ~~known its amount of interruptible demands and Direct Control Load Management (DCLM)~~available to ~~Transmission Operators, Balancing Authorities, and Reliability Coordinators on~~the requester within 30 calendar days following the request.

R2. Each Load-Serving Entity, Transmission Planner, and Resource Planner shall provide the following data annually to the ERO and the Regional Entity: [*Violation Risk Factor: Low*] [*Time Horizon: Operations Assessment*].

- **R2.1.** Interruptible demand and Direct Control Load Management (DCLM) forecast variation, expressed in terms of error divided by actual demand, as well as any biasing of each forecast, for forecasts performed within the previous year.

B. Measures

M1. The Load-Serving Entity, Transmission Planner, and Resource Planner each make known its amount of interruptible demands and DCLM to Transmission Operators, Balancing Authorities and Reliability Coordinators on request within 30 calendar days.

C. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority**

     Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

None specified.

~~1.4.~~1.5. Additional Compliance Information

None.

2. Violation Severity Levels (changes only) ~~of Non-Compliance~~

~~2.1. **Level 1:** Interruptible Demands and DCLM data were provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators, but were incomplete.~~

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

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

~~2.4. **Level 4:** Interruptible Demands and DCLM data were not provided to Reliability Coordinators, Balancing Authorities, and Transmission Operators.~~

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R2				The responsible entity failed to annually provide interruptible demand and Direct Control Load Management(DCLM) forecast variation, expressed in terms of error divided by actual demand, as well as any biasing of each forecast, for forecasts performed within the previous year.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 1287.	Revised.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraph 1300.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
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None.

A. Introduction

1. **Title:** **Documentation of the Accounting Methodology for the Effects of ~~Controllable~~ Demand-Side Management in Demand and Energy Forecasts.**

2. **Number:** MOD-021-~~0.1~~1

3. **Purpose:** To ensure that assessments and validation of past events and databases can be performed, reporting of actual Demand data is needed. Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. In addition, to assist in proper real-time operating, load information related to ~~controllable~~ Demand-Side Management (DSM) programs is needed.

4. **Applicability:**

   4.1. Load-Serving Entity

   4.2. Transmission Planner

   4.3. Resource Planner

5. **(Proposed) Effective Date:** The first day of the first calendar quarter after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees' adoption. ~~December 10, 2009~~

B. Requirements

R1. The Load-Serving Entity, Transmission Planner and Resource Planner's forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed.

R2. The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

R3. The Load-Serving Entity, Transmission Planner and Resource Planner shall each make documentation on the treatment of its DSM programs available to NERC on request (within 30 calendar days).

C. Measures

M1. The Load-Serving Entity, Transmission Planner and Resource Planner forecasts clearly document how the demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible demands, and Direct Control Load Management) are addressed.

M2. The Load-Serving Entity, Transmission Planner and Resource Planner information detailing how Demand-Side Management measures are addressed in the forecasts of Peak Demand and annual Net Energy for Load are included in the data reporting procedures of Reliability Standard MOD-016-0_R1.

M3. The Load-Serving Entity, Planning Authority and Resource Planner shall each provide evidence to its Compliance Monitor that it provided documentation on the treatment of DSM programs to NERC as requested (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Compliance Monitor:~~ Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

None specified.

~~1.4.~~1.5. Additional Compliance Information

None.

2. Violation Severity Levels (no changes) ~~of Non-Compliance~~

~~**2.1. Level 1:** Documentation on the treatment of DSM programs in the demand and energy forecasts was provided, but was incomplete.~~

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

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

~~**2.4. Level 4:** Documentation on the treatment of DSM programs in the demand and energy forecasts was not provided.~~

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0.1	April 15, 2009	R1. – comma inserted after Load-Serving Entity	
0.1	December 10, 2009	Approved by FERC — Added effective date	Update
1	TBD	Modified to address Order No. 693 Directives contained in paragraph 1300.	Revised.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 1469.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-~~1~~2

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.

   4.4. Transmission Operator

   4.5. Load Serving Entity

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.~~August 1, 2006~~

B. Requirements

R1. The Transmission Owner and any ~~Distribution Provider~~entity listed below that individually or jointly 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~~Entity's procedures ~~developed for Reliability Standard PRC-003 Requirement 1~~.

R1.1. Distribution Provider

R1.2. Transmission Operator

R1.3. Load Serving Entity

~~**R1.**~~**R2.** The Generator Owner shall analyze its generator 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~~Entity's procedures ~~developed for PRC-003 R1~~.

R3. The Transmission Owner, the Generator owner, and any ~~Distribution Provider~~entity listed below that individually or jointly 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~~Entity's procedures ~~developed for PRC-003 R1~~.

R3.1. Distribution Provider

R3.2. Transmission Operator

R3.3. Load Serving Entity

C. Measures

M1. The Transmission Owner, and any Distribution Provider, Transmission Operator, or Load Serving Entity 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, Transmission Operator, or Load Serving Entity 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~~Enforcement Authority

Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

~~One calendar year.~~ Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. Data Retention

The Transmission Owner, ~~and~~ Distribution Provider that owns a transmission Protection System, Load Serving Entity that owns a transmission Protection System, Transmission Operator that owns 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.~~1.5. 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. Violation Severity Levels (no changes) ~~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	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
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.

Development Steps Completed:

1. SAR posted for comment (June 18, 2010 through July 13, 2010).
2. First draft of proposed standard posted (June 18, 2010 through July 13, 2010).
3. Posted for 15-day pre-ballot review (June 18 – July 2, 2010).

Proposed Action Plan and Description of Current Draft:

This is the first draft of the proposed standard. The modifications included in this standard are being proposed through an expedited process in order to be responsive to directives from FERC Order No. 693.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct initial ballot on a line-item basis.	July 3 – 13, 2010
2. Post response to comments on initial ballot.	July 20, 2010
3. Conduct recirculation ballot.	July 20 – 30, 2010
4. Submit standard to BOT for adoption.	August 2010
5. File standard with regulatory authorities.	September 2010

DEFINITIONS OF TERMS USED IN STANDARD

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. **Title:** **Voltage and Reactive Control**

2. **Number:** VAR-001-~~1~~2

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.

   ~~4.2.~~4.3. Load Serving Entities.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.~~Six months after BOT adoption~~.

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 – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding – 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 and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding – to satisfy its reactive requirements identified by its Transmission Service Provider.

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

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.

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to,~~including~~ reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load, and, if necessary, load shedding – 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~~Enforcement Authority

Regional ~~Reliability Organization~~Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.3.~~1.4. 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.~~1.5. 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~~Violation Severity Levels (no changes)

~~**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	Errata

		Operators" to Applicability section.	
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	TBD	Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised.