Exhibit A

Proposed Reliability Standards

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(ii)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:**

   See the Implementation Plan for PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

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

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

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

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

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

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

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

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

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

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

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

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection	

		System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii)	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Guidelines and Technical Basis

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

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

~~Standard Development Timeline~~

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

~~Development Steps Completed~~

~~SAR posted for comment November 20 – December 19, 2013.~~

~~The Standards Committee authorized this posting on September 30, 2014.~~

~~Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.~~

~~Description of Current Draft~~

~~PRC-001-1.1(Xii)[1] is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.~~

~~Anticipated Actions~~	~~Anticipated Date~~
~~Final ballot~~	~~January 2015~~
~~BOT adoption~~	~~February 2015~~

~~*When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.*~~

[1] ~~The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] ~~The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.~~

A. Introduction

1. **Title:** **System Protection Coordination**
2. **Number:** PRC-001-1.1~~(X~~ii)
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.
4. **Applicability**
   - **4.1.** Balancing Authorities
   - **4.2.** Transmission Operators
   - **4.3.** Generator Operators
5. **Effective Date:** ~~January 1, 2007~~

   See the Implementation Plan for ~~this standard~~PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

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

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

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R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

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

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

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

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R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

1.3. Data Retention

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

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E. Regional Differences

None identified.

Version History

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Guidelines and Technical Basis

Rationale:

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

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

A. Introduction

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

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

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

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

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

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

4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

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

5. **Effective Date:**

See the Implementation Plan for PRC-019-2.

B. Requirements

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

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

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

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

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

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

C. Measures

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

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

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

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

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

E. Regional Variances

None.

F. Associated Documents

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

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

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

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

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

G. Reference

Examples of Coordination

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

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

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

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

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

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

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

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

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

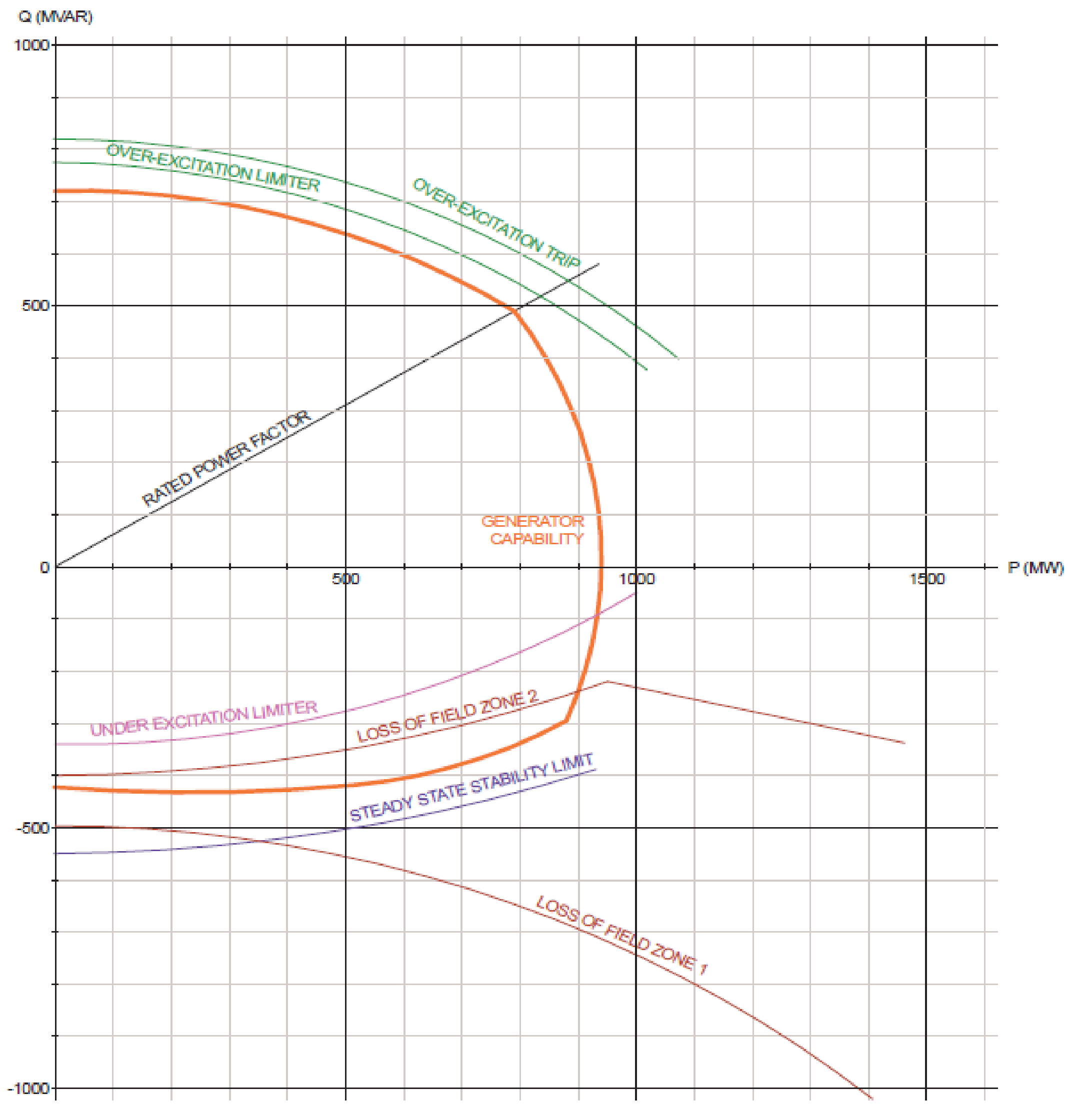
$R = V^2{}_g/2*(1/X_s+1/X_d)$

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

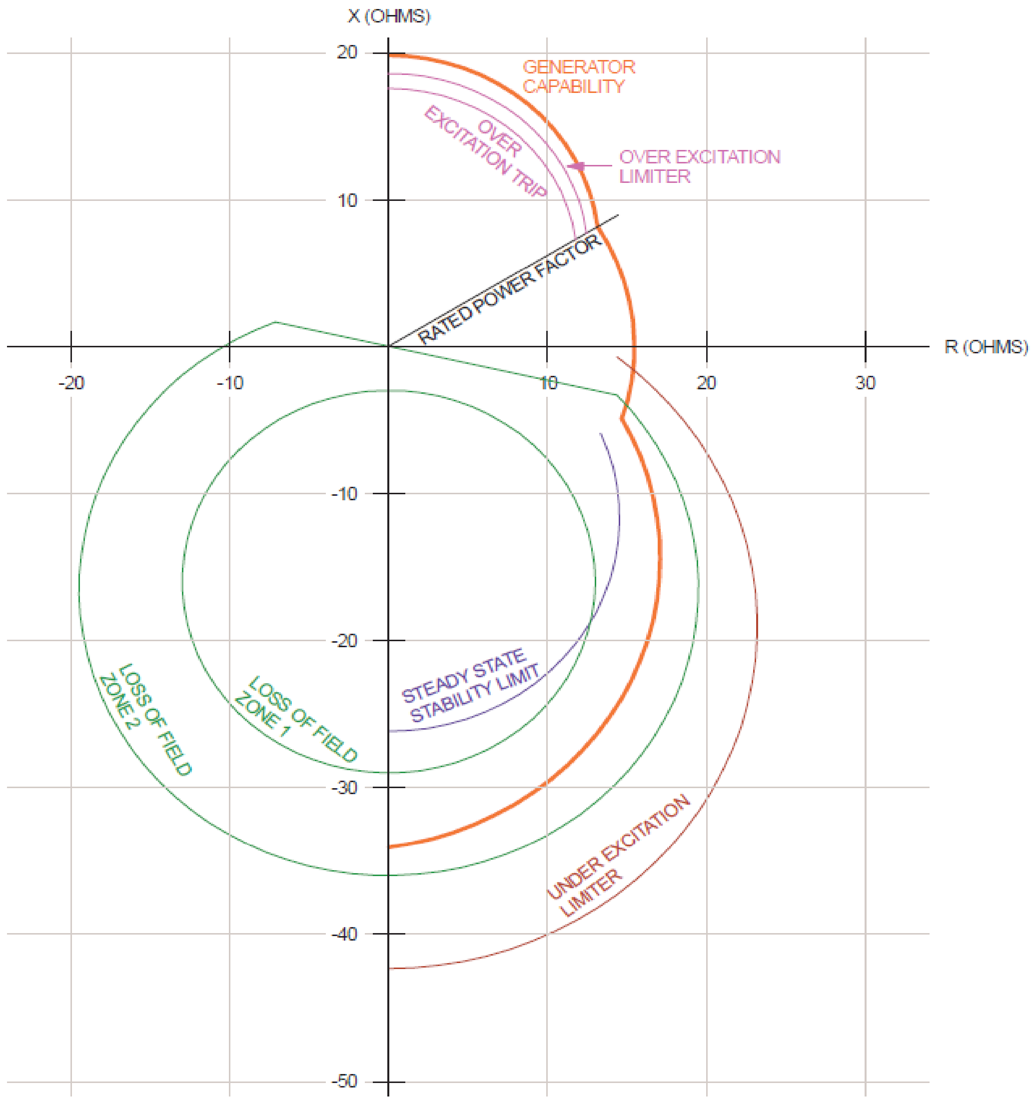
$C = (X_d-X_s)/2$

$R = (X_d+X_s)/2$

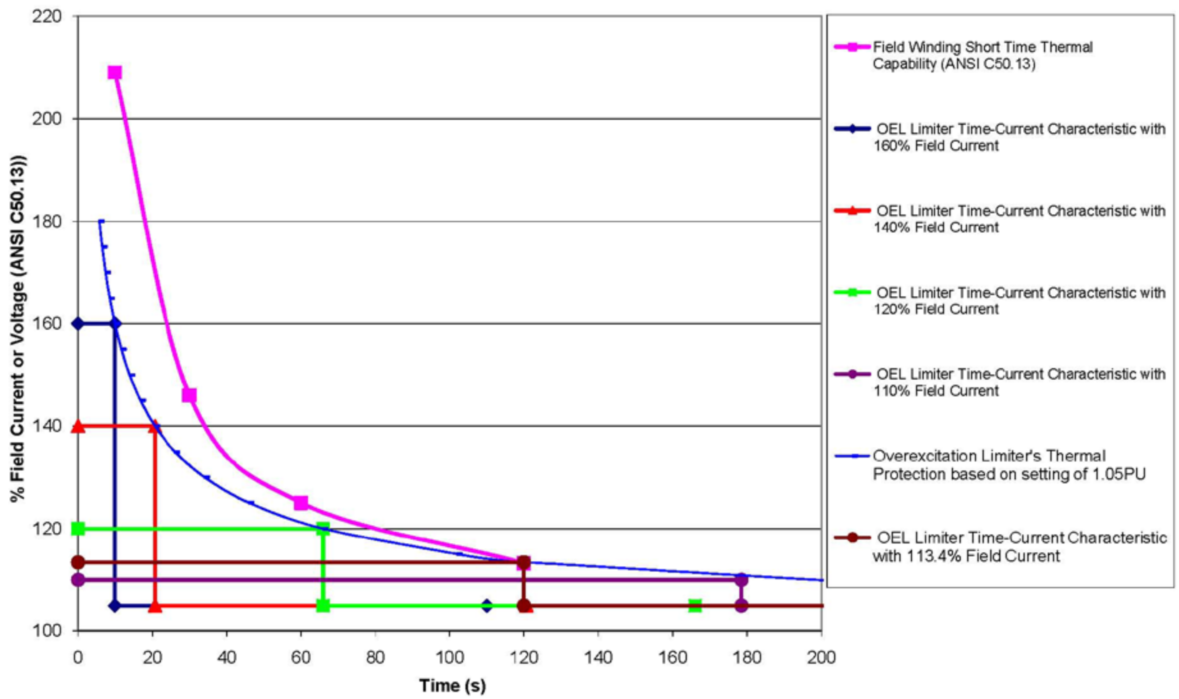
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

Guidelines and Technical Basis

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

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

~~Standard Development Timeline~~

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

~~Development Steps Completed~~

1. ~~SAR posted for comment November 20 – December 19, 2013.~~
2. ~~The Standards Committee authorized this posting on September 30, 2014.~~
3. ~~Initial posting of revised standard PRC-019-2 on November 5, 2014.~~

~~Description of Current Draft~~

~~PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.~~[1]

~~Anticipated Actions~~	~~Anticipated Date~~
~~Final ballot~~	~~January 2015~~
~~BOT adoption~~	~~February 2015~~

~~[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.~~

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

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

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

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

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

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

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

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

4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource ~~level~~. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

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

5. Effective Date:

See the Implementation Plan for PRC-019-2~~this standard~~.

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

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

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

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

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

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

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

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

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

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

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

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

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

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

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

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment

	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

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

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

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

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

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

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)~~	
2	February 12, 2015	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

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

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

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

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

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

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

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

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

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

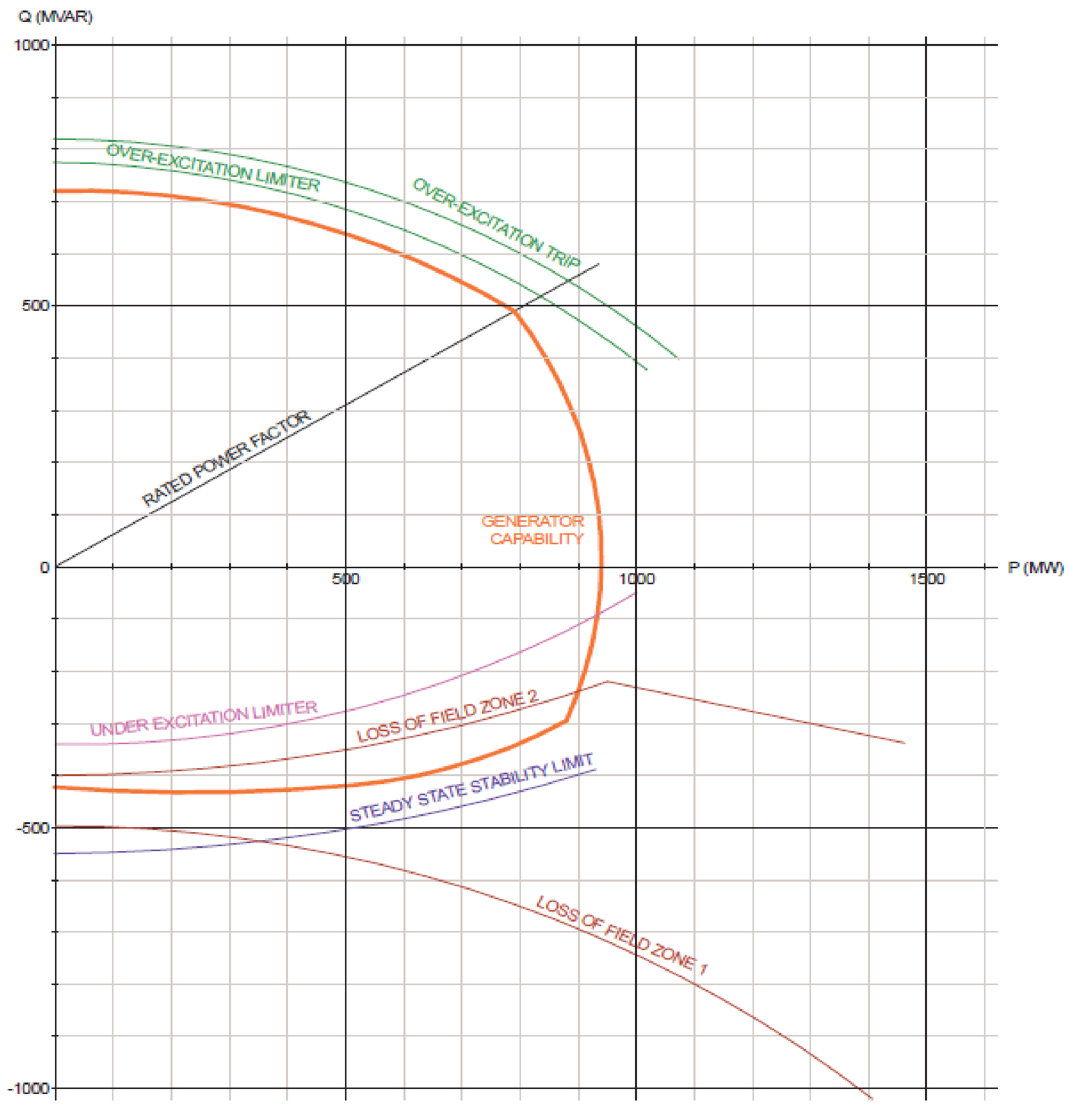
$$R = V^2_g/2*(1/X_s+1/X_d)$$

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

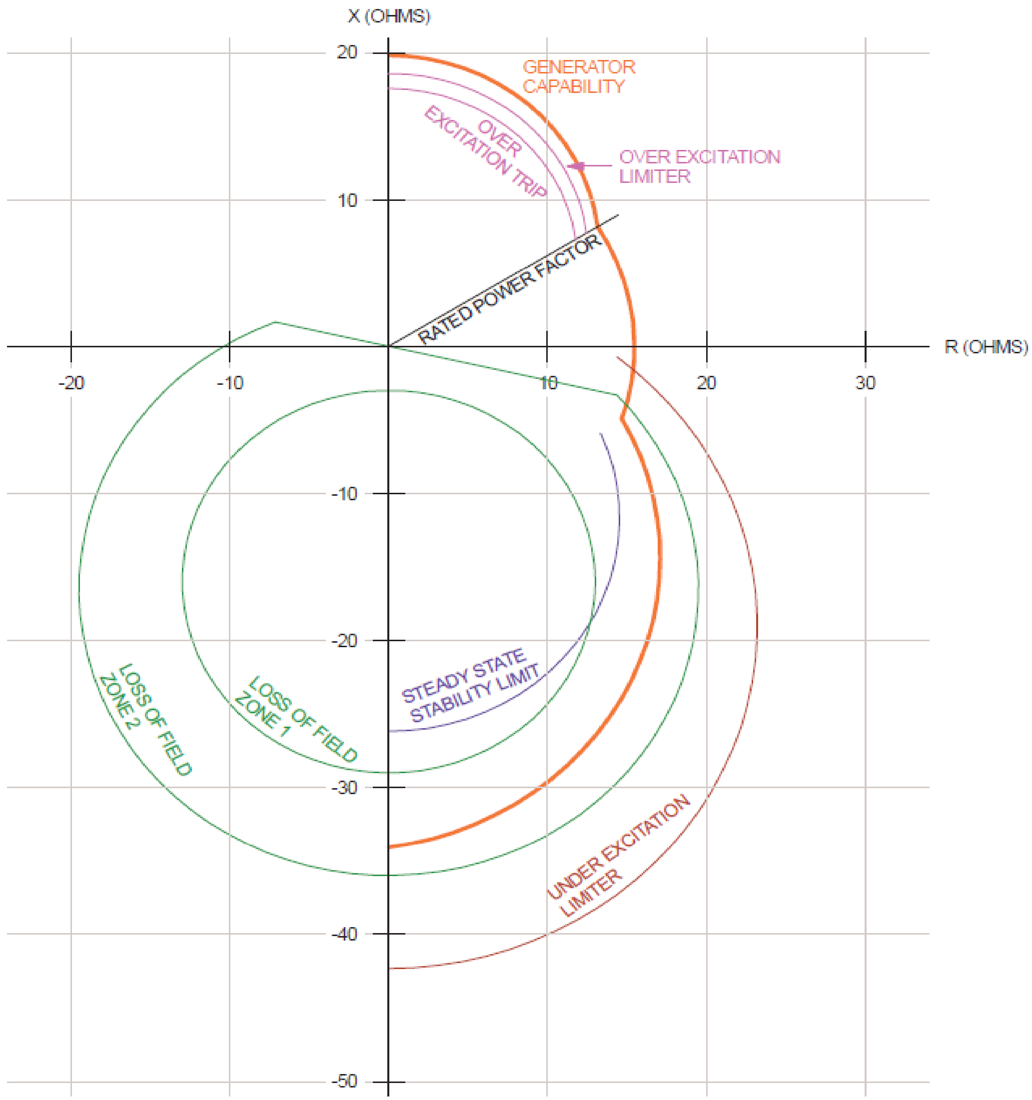
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

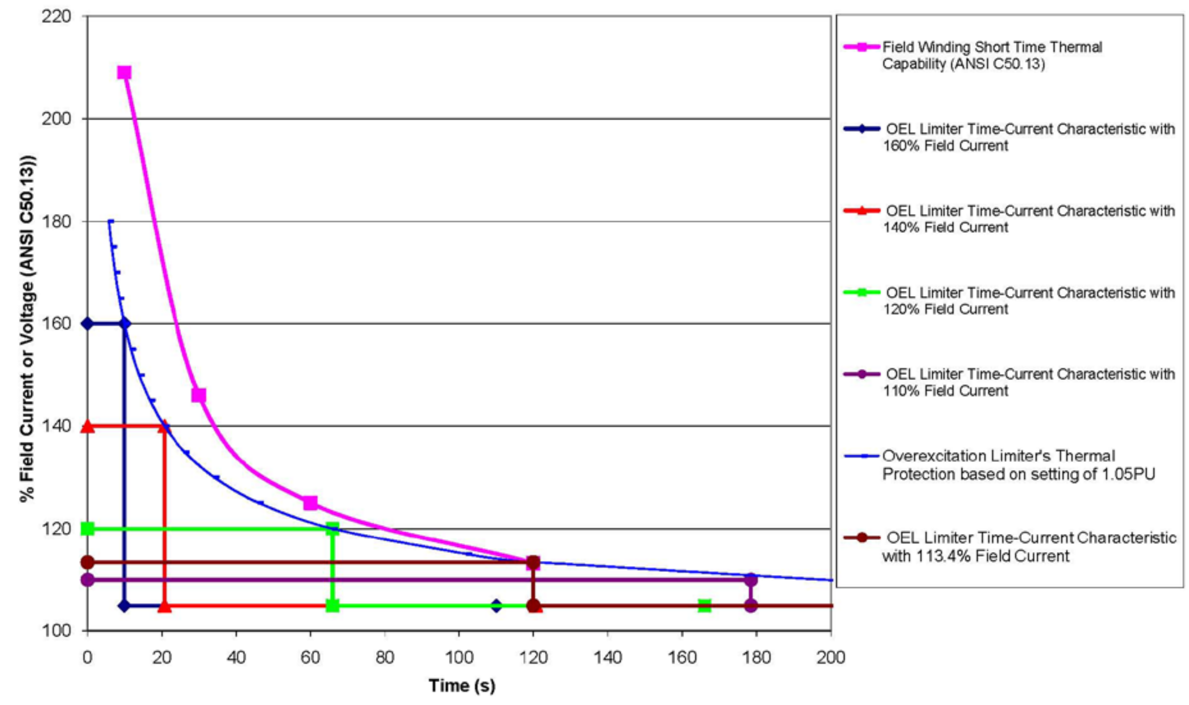
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Guidelines and Technical Basis

Rationale:

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

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
   4.1. Generator Owner
5. **Effective Date:**
   See the Implementation Plan for PRC-024-2.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[2] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R2. Each Generator Owner that has generator voltage protective relaying[1] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

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[1] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[2] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection[3]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[4] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[5] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.

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[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[4] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[5] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

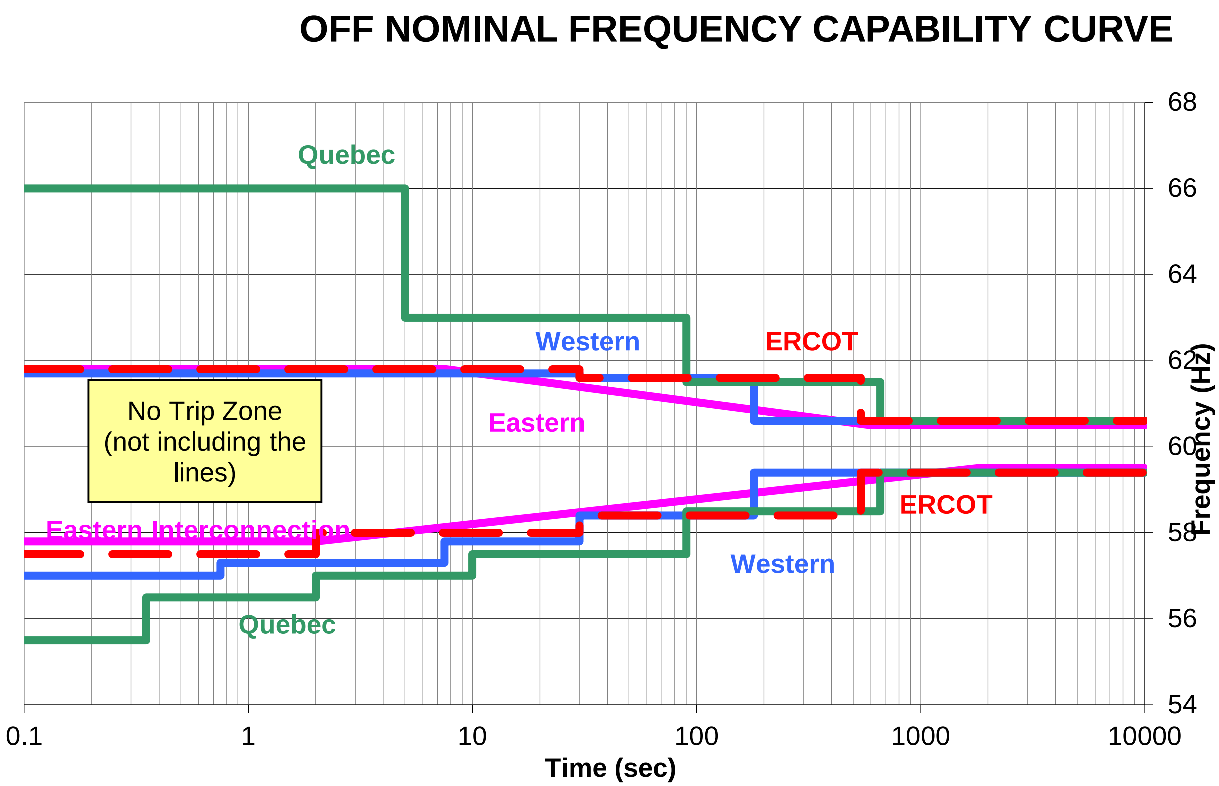
F. Associated Documents

None

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

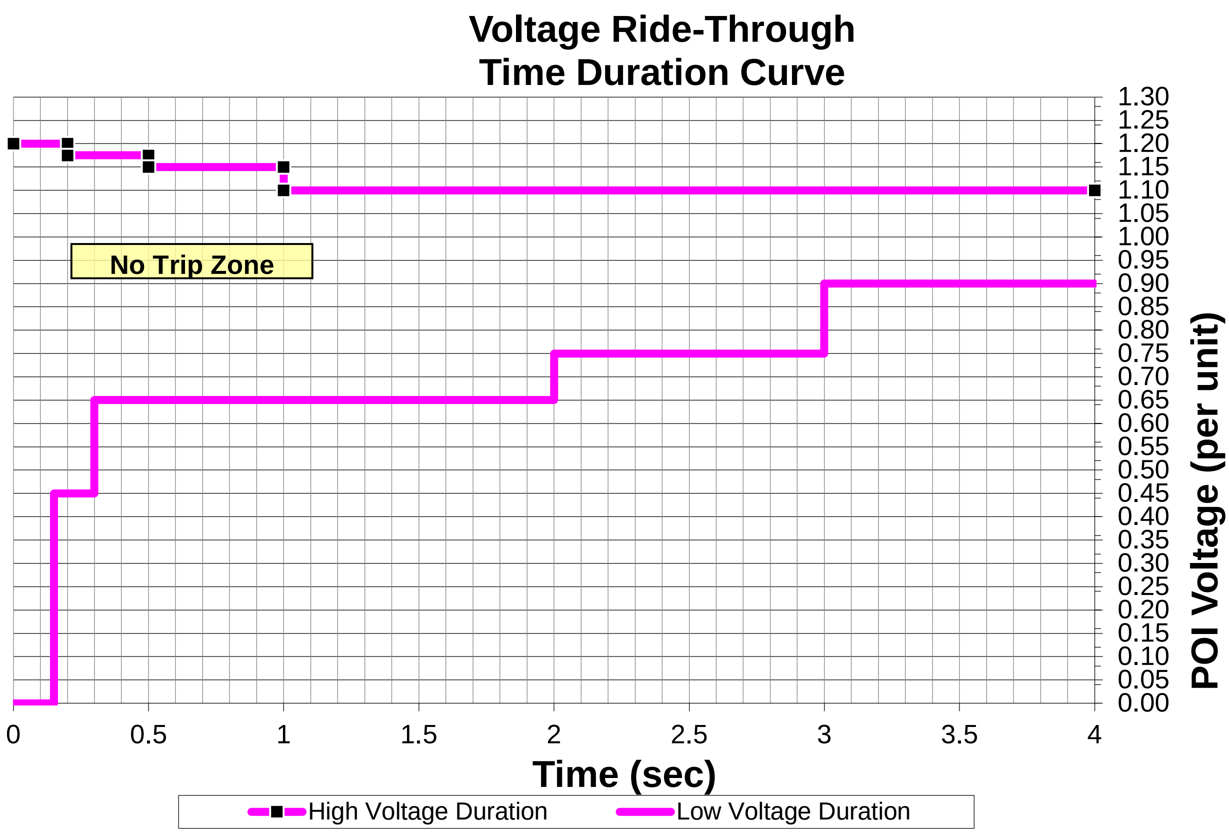
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

Guidelines and Technical Basis

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

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the “no-trip zone” referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

Standard Development Timeline

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

Development Steps Completed

- SAR posted for comment November 20 – December 19, 2013.
- The Standards Committee authorized this posting on September 30, 2014.
- Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-21(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.currently had includes an (X) to indicate the version numbering will be updated, and . Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will since assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2~~1~~~~(X)~~
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. Generator Owner

5. **Effective Date:**

   See the Implementation Plan for PRC-024-2~~this standard.~~

~~In those jurisdictions where regulatory approval is required:~~

~~By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~In those jurisdictions where regulatory approval is not required:~~

~~By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

~~**Rationale for Footnotes 24 and 46**~~

~~The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respectingwithin the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.~~

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.

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[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

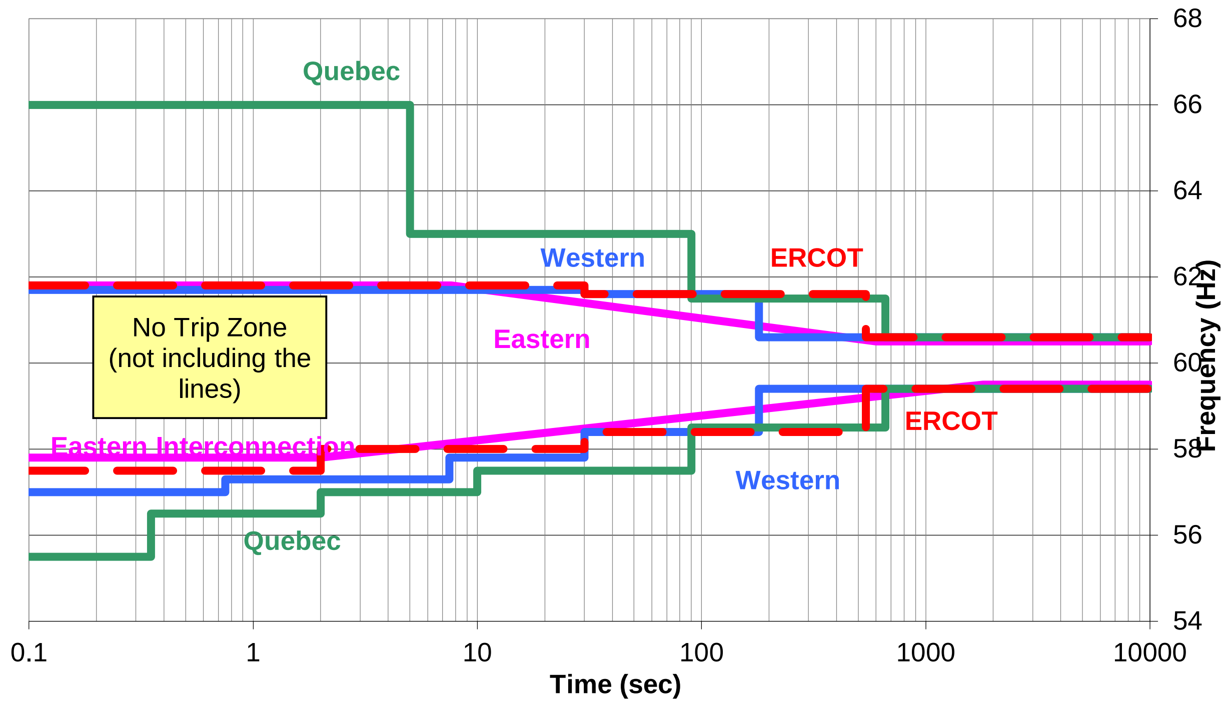
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)~~	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

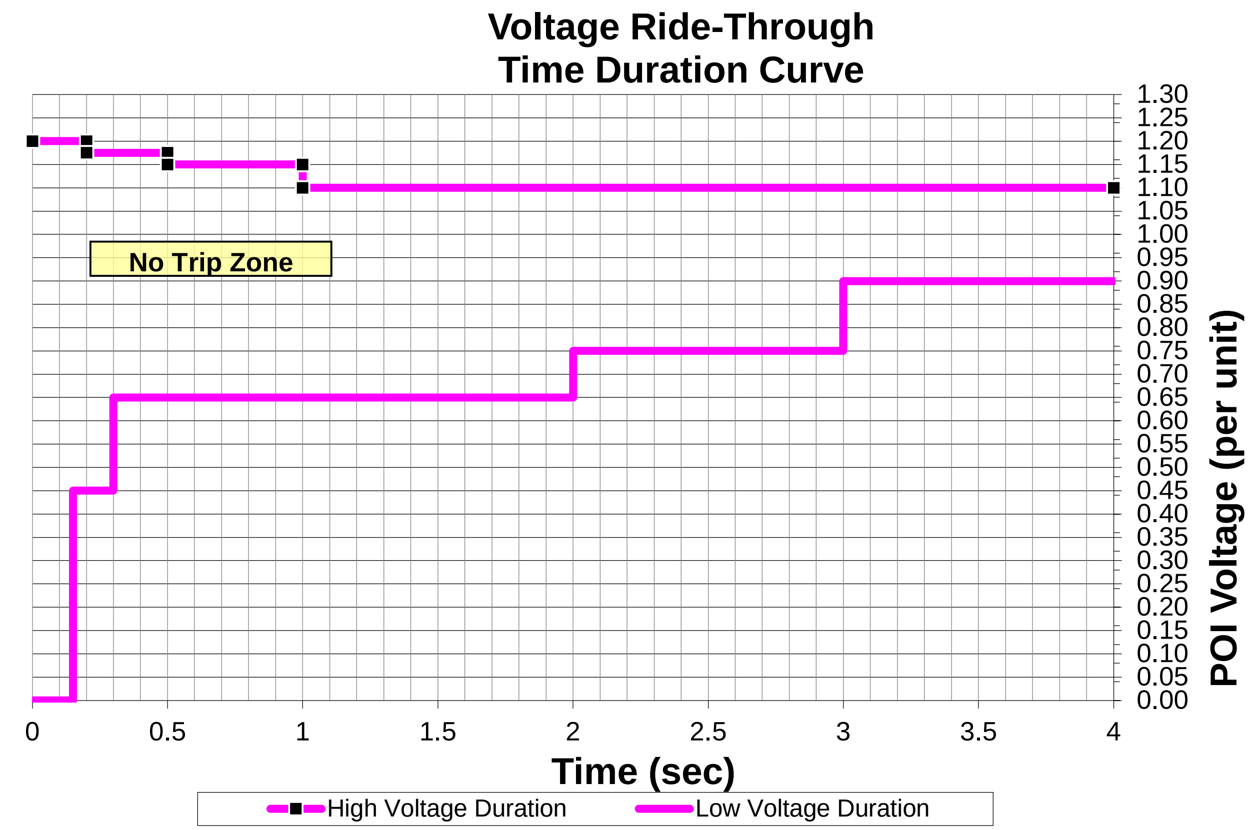
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Guidelines and Technical Basis

Rationale:

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

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

Exhibit B

Implementation Plans

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(ii)

Standards Involved

Approval:

- PRC-001-1.1(ii) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i))

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-001-1.1(ii) is proposed for approval to align the applicability of PRC-001-1.1 with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.

Effective Date

PRC-001-1.1(ii) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1 (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i)), shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(ii).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved

Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements.

Effective Date

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

PRC-019-2 shall become effective on the later of the first day following the Effective Date of PRC-019-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-019-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of “Bulk Electric System” is available here.

The Implementation Plan for PRC-019-1 is available here.

Implementation Plan

Dispersed Generation Resources
PRC-024-2

Standards Involved
Approval:

- PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations
PRC-024-2 is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options.

Effective Date
PRC-024-2 shall become effective on the later of the first day following the Effective Date of PRC-024-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-024-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-2.

Applicability:

This standard applies to the following functional entities:

- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

Exhibit D

Summary of Development History and Complete Record of Development of Proposed Reliability Standards

Exhibit D: Summary of Development History

The development record for the proposed Reliability Standards is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO[1]. The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in Exhibit E.

II. Standard Development History

A. Standard Authorization Request ("SAR") Development

A SAR for Project 2014-01 Standards Applicability for Dispersed Generation Resources ("DGR") was posted for a 30-day formal comment period from November 20, 2013 through December 19, 2013. The NERC Standards Committee approved the revised SAR on October 17, 2013.

B. First Posting - Formal Comment Period, Initial Ballots

Proposed Reliability Standards, PRC-001-1.1(X), PRC-019-2 and PRC-024-1 (X), were posted for a 45-day public comment period from November 5, 2014 December 23, 2014 with an initial ballot conducted from December 10, 2014 through December 23, 2014. The initial ballot for PRC-001-1.1 (X) achieved 79.38% quorum, and an approval of 92.69%, PRC-019-2 achieved 79.72% quorum, and an approval of 93.55%, and PRC-024-1 (X) achieved 79.60% quorum, and an approval of 93.67%. There were 25 sets of comments, including comments from

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d) (2) (2012).

approximately 98 different individuals and approximately 69 companies, representing all 10 industry segments.

The standard drafting team considered stakeholder comments regarding the proposed Reliability Standards and made modifications based on those comments. A summary of the responses to comments and changes made is included in the Consideration of Comments for the posting.

C. Final Ballots

Proposed Reliability Standards PRC-001-1.1 (ii), PRC-019-2 and PRC-024-2 were posted for a 10-day final ballot period from January 13, 2015 through January 22, 2015. PRC-001-1.1 (ii) achieved 89.27% quorum, and an approval of 93.99%, PRC-019-2 achieved 89.30% quorum, and an approval of 94.03% and PRC-024-2 achieved 89.52% quorum, and an approval of 95.82%.

D. Board of Trustees Adoption

Proposed Reliability Standards PRC-001-1.1 (ii), PRC-019-2 and PRC-024-2 were adopted by the NERC Board of Trustees on February 12, 2015.

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Related Files

Status

A final ballot for **PRC-005-5- Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance** is open through **8 p.m. Eastern on March 11, 2015**. Voting results will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Board Adopted November 13, 2014 - PRC-004-2.1(i)a, PRC-004-4, PRC-005-2(i), and PRC-005-3(i)

Filed with FERC

Order Effective

Enforcement Date

Background:

The Standards Authorization Request (SAR) asks that the applicability section of certain Reliability Standards that apply to a Generator Owner (GO)/Generator Operator (GOP) or the requirements of certain GO/GOP Reliability Standards be reviewed, and where appropriate revised to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). Dispersed generation resources are those resources that are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

This request is related to the revised definition of the Bulk Electric System (BES) from Project 2010-17, and it is desirable to complete any revisions determined to be necessary so that revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the revised BES definition. This effective date is expected to be July 1 2016, although it is possible that regulatory action could change the date.

Draft	Actions	Dates	Results	Consideration of Comments

Errata Change:

On November 13, 2014, the NERC Board of Trustees (Board) adopted PRC-006-2 PRC 004-2.1(i)a, PRC-004-4, PRC-005-2(i), and PRC-005-3(i). Each of these standards, or its associated documents, contain inadvertent errors that needed to be corrected prior to filing with applicable regulatory authorities. The standards referenced the implementation plan in the Effective Date section. As a result, there are no associated changes to the standard with the corrections.

Each error and how the corrections meet the required elements of an errata change are described below.

References to "(X)" in Implementation Plans for PRC-004-2(i)a, PRC-005-2(i), and PRC-005-3(i) needed to be changed to align the standard versions with the updated NERC standards numbering convention.

The Effective Date language in the Implementation Plan for PRC-004-4 needed to be corrected to properly sequence version 4 to become effective concurrently with or after version 3. The implementation plan provided for an immediate effective date, which in some scenarios could make version 4 effective prior to version 3, which has a 12 month period after approval before it becomes effective. The drafting team intended to sequence the standards to ensure that version 4 did not go into effect prior to version 3, but went into effect immediately upon approval if version 3 was effective.

A correction was also needed to ensure version 4 becomes effective on the later of the effective date of PRC-004-3 or the date that PRC-004-4 is approved by an applicable governmental authority. A conforming correction to reference the effective date of PRC-004-3 rather than "12 months following the approval of PRC-004-3" to make sure that the implementation timing for PRC-004-3 is properly cross referenced was also needed.

Implementation Plans

PRC-005-2(i)
Clean | Redline to Last Approved

PRC-005-3(i)
Clean | Redline to Last Approved

PRC-004-2.1(i)
Clean | Redline to Last Approved

PRC-004-4
Clean | Redline to Last Approved

Final Draft **PRC-005-5** Clean | Redline to Last Posted | Redline to PRC-005-4 **Implementation Plan** Clean | Redline to Last Posted **Supporting Documents** SAR	Final Ballot Info>> Vote>>	03/02/15 – 03/11/15		
Final Drafts **PRC-001-1.1(ii)** Clean **(28)** | Redline to Last Posted **(29)** | Redline to PRC-001-1.1 **(30)** **PRC-019-2** Clean **(31)** | Redline to Last Posted **(32)** | Redline to PRC-019-1 **(33)** **PRC-024-2** Clean **(34)** | Redline to Last Posted **(35)** | Redline to PRC-024-1 **(36)** **Implementation Plans** **PRC-001-1.1(ii)** Clean	Final Ballots Info>> **(44)** Vote>> (Closed)	01/13/15 - 01/22/15	Summary>> **(45)** Ballot Results PRC-001-1.1(ii)>> **(46)** PRC-019-2>> **(47)** PRC-024-2>> **(48)**	

(37) | Redline to Last Posted **(38)** **PRC-019-2** Clean **(39)** | Redline to Last Posted **(40)** **PRC-024-2** Clean **(41)** | Redline to Last Posted **(42)** SAR **(43)**				
White Paper Clean | Redline to Last Posted **Appendix A** – List of all NERC standards applicable to GOs/GOPs **Appendix B** – NERC standards recommended for consideration to clarify applicability for dispersed generation Unofficial Comment Form(Word)	Comment Period Info>> Submit Comments>> (Closed)	12/22/14 - 01/20/15	Comments Received>>	
Draft 1 PRC-005-5 Clean | Redline to Last Posted	Initial Ballot Info>> Vote>> (Closed)	1/12/15 – 1/22/15	Summary>> Ballot Results>>	Consideration of Comments>>

Implementation Plan **Supporting Documents** Unofficial Comment Form (Word) SAR	Comment Period Info>> Submit Comments>> (Closed)	12/8/14 – 1/22/15	Comments Received>>	
	Join Ballot Pool Info>> Join>> (Closed)	12/8/14 – 1/8/15		
Draft 1 Standards **PRC-001-1.1(X)** Clean **(6)** | Redline to PRC-001-1.1 **(7)** **PRC-019-2** Clean **(8)** | Redline to PRC-019-1 **(9)** **PRC-024-1(X)** Clean **(10)** | Redline to last posted PRC-024-1 **(11)** **Implementation Plans** PRC-001-1.1(X) **(12)** PRC-019-2 **(13)**	Initial Ballots Updated Info>> **(17)** Info>> **(18)** Vote>> (Closed)	12/10/14 – 12/23/14	Summary>> **(21)** Ballot Results PRC-001-1.1(X) **(22)** PRC-019-2 **(23)** PRC-024-1(X) **(24)**	Consideration of Comments>> Clean **(26)** | Redline **(27)**
	Comment Period Info>> **(19)** Submit Comments>> (Closed) The ballots and comment period have heen extended one additional day to 8 p.m. Eastern on Tuesday,	11/5/14 – 12/23/14	Comments Received>> **(25)**	

PRC-024-1(X) **(14)** **Supporting Documents** Unofficial Comment Form (Word) **(15)** SAR **(16)**	December 23, 2014 in order to reach quorum Join Ballot Pools Info>> **(20)** Join>> (Closed) The comment period and initial ballot close dates have been extended one day to December 22, 2014 (for the medium-priority Reliability Standards) due to a NERC.com maintenance outage that occurred on Saturday, December 13, 2014.	11/5/14 – 12/4/14		
Final Drafts **PRC-004-2.1(i)a** Clean | Redline to last posted Redline to PRC-004-2.1a **PRC-004-4** Clean | Redline to last posted Redline to PRC-004-3 **VAR-002-4** Clean | Redline to last posted Redline to VAR-002-3	Final Ballots Info>> Vote>> (Closed)	10/28/14 – 11/06/14	Summary>> Ballot Results PRC-004-2.1(i)a>> PRC-004-4>> VAR-002-4>>	

Implementation Plans **PRC-004-2.1(i)a** Clean (No changes to last posted) **PRC-004-4** Clean (No changes to last posted) **VAR-002-4** Clean (No changes to last posted) SAR				
Draft 2 Standard **PRC-004-2.1a(X)** Clean | Redline to PRC-004-2.1a Redline to last posted **PRC-004-4** Clean | Redline to PRC-004-3 Redline to last posted **Implementation Plans** PRC-004-2.1a(X) Clean | Redline to last posted PRC-004-4 Clean | Redline to last posted	Additional Ballots Updated Info>> Info>> Vote>> (Closed)	10/10/14 - 10/22/14	Summary>> Ballot Results PRC-004-2.1a(X)>> PRC-004-4>>	Consideration of Comments PRC-004>> VAR-002-4>>
	Comment Period Info>> Submit Comments>> (Closed)	9/5/14 - 10/22/14	Comments Received>>	

Supporting Documents Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR				
Draft 2 **PRC-005-2(X)** Clean Redline to last posted Redline to PRC-005-2 **PRC-005-3(X)** Clean Redline to last posted Redline to PRC-005-3 **Implementation Plans** PRC-005-2(X) PRC-005-3(X) **Supporting Documents** Coordination Plan and Explanation of Version Numbers SAR	Final Ballots Info>> Vote>> (Closed)	8/27/14 – 9/5/14	Summary>> Ballot Results PRC-005-2(X)>> PRC-005-3(X)>>	
Draft 2 **VAR-002-2b(X)**	Additional Ballots Updated Info>>	10/7/14 – 10/16/14	Summary>>	

Clean Redline to Last Posted Redline to VAR-002-2b **VAR-002-4** Clean Redline to last posted Redline to VAR-002-3 **Implementation Plan** VAR-002-2b(X) VAR-002-4 **Supporting Documents** Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR	Info>> Vote>> (Closed)		Ballot Results VAR-002-4>> VAR-002-2b(X)>>	
	Comment Period Info>> Submit Comments>> (Closed)	8/27/14 – 10/16/14	Comments Received>>	
Draft 1 Standard **PRC-004-2.1a(X)** Clean | Redline to PRC-004-2.1a **PRC-004-3(X)** Clean | Redline to PRC-004-3 **Implementation Plans** PRC-004-2.1a(X)	Initial Ballots Updated Info>> Info>> Vote>> (Closed)	8/15/14 – 8/26/14	Summary>> Ballot Results PRC-004-2.1a(X)>> PRC-004-3(X)>>	
	Comment Period Info>>	7/10/14 – 8/26/14	Comments Received>>	Consideration of Comments>>

PRC-004-3(X) **Supporting Documents** Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR **Draft Reliability Standard Audit Worksheets (RSAW)** PRC-004-2.1a PRC-004-3 PRC-005-1.1b	Submit Comments>> (Closed)			
	Join Ballot Pools>> (Closed) Please note: As a convenience to stakeholders, if you have previously joined the ballot pool for VAR-002-2b(X), no action is needed - you have automatically been entered into both the PRC-004-2.1a(X) and PRC-004-3(X) ballot pools. If you have been automatically entered and do not wish to participate, please contact Wendy Muller **prior to July 16, 2014** to have your name removed.	7/10/14 - 7/16/14		
Draft 1 Standards **PRC-005-2(X)** Clean | Redline to PRC-005-2 **PRC-005-3(X)** Clean | Redline to PRC-005-3 **PRC-005-X(X)** Clean | Redline to last posted PRC-005-X **VAR-002-2b(X)** Clean | Redline to VAR-002-2b	Initial Ballots Updated Info>> Info>> Vote>> (Closed)	7/18/14 – 7/29/14	Summary>> Ballot Results: PRC-005-2(X)>> PRC-005-3(X)>> PRC-005-X(X)>> VAR-002-2b(X)>> VAR-002-4>>	

VAR-002-4 Clean | Redline to VAR-002-3 **Implementation Plans** PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4 **Supporting Documents** Unofficial Comment Form (Word) Coordination Plan and Explanation of Version Numbers SAR **Draft Reliability Standard Audit Worksheets (RSAW)** VAR-002-2b VAR-002-3	Formal Comment Period Info>> Submit Comments>> (Closed)	6/12/14 – 7/29/14	Comments Received>>	Consideration of Comments>>
	Join Ballot Pool Info>> Join>> (Closed) Please note: these ballot pool join periods have been extended to 8 p.m. Eastern on Wednesday, July 16, 2014 in order to keep the closing dates for Project 2014-01 the same.	6/12/14 – 7/16/14		
White Paper **Appendix A** – List of all NERC standards applicable to GOs/GOPs	Informal Comment Period Info>> Submit Comments>>	04/17/14 - 05/05/14	Comments Received>>	Consideration of Comments>>

Appendix B – NERC standards recommended for consideration to clarify applicability for dispersed generation Unofficial Comment Form				
SAR **(1)** **Supporting Documents:** Unofficial Comment Form (Word) **(2)**	Comment Period Info>> **(3)** Submit Comments>>	11/20/13 - 12/19/13 (closed)	Comments Received>> **(4)**	Consideration of Comments>> **(5)**

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard. **PRC-005-2** Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply. **FAC-008-3** For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Standard Authorization Request - Application of Certain GO/GOP Reliability Standards and Requirements to Dispersed Generation

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the definition. The electronic comment form must be completed by **December 19, 2013**.

All documents and information about this project are available on the project page. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information

The Standards Authorization Request (SAR) asks that the applicability section of certain Reliability Standards that apply to a Generator Owner (GO)/Generator Operator (GOP) or the requirements of certain GO/GOP Reliability Standards be reviewed, and where appropriate revised to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the Bulk Electric System (BES). Dispersed generation resources are those resources that are small-scale power generation technologies using a system designed primarily for aggregating capacity providing an alternative to, or an enhancement of, the traditional electric power system. Examples could include but are not limited to solar, geothermal, energy storage, flywheels, wind, micro-turbines, and fuel cells.

This request is related to the revised definition of the Bulk Electric System (BES) from Project 2010-17, and it is desirable to complete any revisions determined to be necessary so that revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the revised BES definition. This effective date is expected to be July 1 2016, although it is possible that regulatory action could change the date.

The scope of the SAR involves review of and possible revisions to the applicability section of the following Reliability Standard applicability sections and/or Reliability Standard requirements applicable to GOs/GOPs: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, any IRO, MOD, PRC, or TOP standards that require outage and protection and control coordination, planning, next day study or real time data, or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter, or unit level for dispersed generation.

The scope of work would also include development of a technical guidance paper for Standard Drafting Teams developing new or revised standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES.

To the extent there are existing Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

   Yes:

   No:

   Comments:

2. Do you agree that the scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources, or should the scope encompass consideration of changes to standards applicability for all small generation regardless of type? Please provide a technical rationale for your response.

   Yes:

   No:

   Comments:

3. Do you agree with the list of standards to be reviewed? If you do not agree, please note specific standards you think should be added to or removed from the list.

   Yes:

   No:

   Comments:

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this SAR should it move forward? If yes, please identify the business practice.

   Yes:

   No:

   Comments:

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

   Yes:

   No:

   Comments:

6. Are there any other concerns with this SAR that haven't been covered in previous questions?

   Yes:

   No:

   Comments:

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources

SAR Formal Comment Period: November 20, 2013 – December 19, 2013

Now Available

A 30-day formal comment period for the Project 2014-01 Standards Applicability for Dispersed Generation Resources Standard Authorization Request (SAR) is now open through **8 p.m. Eastern on Thursday, December 19, 2013.**

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, December 19, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

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Individual or group. (28 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (28 Responses)
Question 1 (27 Responses)
Question 1 Comments (27 Responses)
Question 2 (24 Responses)
Question 2 Comments (27 Responses)
Question 3 (0 Responses)
Question 3 Comments (27 Responses)
Question 4 (0 Responses)
Question 4 Comments (27 Responses)
Question 5 (0 Responses)
Question 5 Comments (27 Responses)
Question 6 (0 Responses)
Question 6 Comments (27 Responses)

Group
Caithness Shepherds Flat, LLC
Jeffrey Delgado
Yes
Yes
Caithness Shepherds Flat Wind Farm (CSF), located in Oregon, supports the SAR as written and believes the scope should address dispersed generation resources with collector systems only. In the development of CSF’s NERC compliance program, it became apparent that some GO/GOP applicable Reliability Standards were written with fossil fuel facilities in mind, and not generation resources such as wind. The VAR-002 standard for example, requiring reactive and voltage control of individual generators and notification of the TOP when there is a change in status, would appear to be irrelevant to the TOP, but rather the aggregate MW output at the point of interconnection should be what is relevant. CSF’s wind farm consists of several hundred wind turbines, all < 3 MW in nameplate capacity. The TOP does not need to be notified about individual turbine voltage status, as any loss of voltage control of an individual turbine will not be detected by the TOP. The relevant factor is in the voltage at the point of interconnection which is controlled by a “Wind Farm Management System” WFMS voltage control system. Change in status of the WFMS would be of interest to the TOP, so the standard should allow for this variance.
Yes
No
No
No
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
No

Scope should expanded to include all small generators regardless of types. There is no specific reason to not include all. Generally, there is little reliability benefits to BES by applying NERC standards to small generators regardless of the type.
Yes
No
No
No
Group
SPP Standards Review Group
Robert Rhodes
Yes
No
We believe that this evaluation should be extended to all small generation regardless of type because the impact on the BES would be the same regardless of the source or prime mover of the generation.
While we may agree with the list of standards as presented in the SAR we would encourage the SAR drafting team to not limit itself to just those particular standards. For example, once a drafting team is established and work begins on the project, we don't want the project to be limited by the scope as currently defined in the SAR. We need to factor in some flexibility to go beyond this specific list to capture all those standards/requirements/definitions which may be impacted in this review.
Not at this time.
Although we are not aware of any specific federal regulatory requirements, the drafting team needs to keep in mind that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project.
Regarding the July 2016 deadline, the drafting team needs to be sure that this effort is complete in time for the industry to be ready by July 2016. We need to be sure that as the deadline approaches, compliance preparations aren't made and then un-made as a result of a modification to an existing standard which is impacted by this effort. In the 1st line of the 1st paragraph of the Industry Need section under SAR Information, we suggest replacing 'application' with 'applicability'. In the 5th line of the 1st paragraph of the Brief Description section under SAR Information, replace 'real time' with 'Real-time', the NERC Glossary term. In the 1st line of the FAC-008-3 paragraph under SAR Information, hyphenate step-up. In the next to last line of the General review of IROs, MODs, PRCs, TOPs paragraph, change 'uneeded' to 'unneeded'.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes.
No.
Yes. It must be considered that the operating system in Quebec follows chapter R-6.01 An Act Respecting the Regie de L'Energie, which details: (1) an owner or operator of a facility with a capacity of 44 kV or more connected to an electric power transmission system; (2) an owner or operator of an electric power transmission system; (3) an owner or operator of a production facility with a capacity of 50 megavolt amperes (MVA) or more connected to an electric power transmission system; (4) a distributor with a peak capacity of over 25 megawatts (MW), whose facilities are connected to an electric power transmission system; and (5) a person who uses an electric power transmission system under an electric power transmission service agreement with the electric power carrier or with any other carrier in Québec.

No.
Individual
Thomas Foltz
American Electric Power
Yes
AEP would prefer that the solution for applicability of dispersed generation at the turbine or generating unit level would be by adjusting the BES definition accordingly. Creating a new SAR, allowing this topic be discussed within the framework of the BES definition itself, would seem the most direct and efficient way of debating the topic. However, if that cannot be accomplished, AEP supports the effort of this SAR as an alternative (though less desirable) means to accomplish the same goal.
No
We believe it is preferable, at least initially, for the scope to remain limited to dispersed generation resources.
Every standard that involves the GO and/or GOP should be included in the scope of the SAR. This does not imply that all standards should be modified, but the SDT and commenters should be afforded the opportunity to consider the impacts of such changes. For example, PRC-024, PRC-001, CIP-002 through CIP-011, etc. should be considered.
No.
No.
No.
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Yes
No
No
Although we do not have any concerns with this SAR, we have the following suggestions to improve clarity. (1) Industry Need - remove the words “Bulk Electric System” from the second paragraph to leave only the acronym, BES because this is the second instance of BES in the document. (2) SAR Information - capitalize ‘misoperation’ because it appears in the Glossary of Terms.
Individual
Patricia Metro
National Rural Electric Cooperative Association
No
NRECA does not believe this SAR is necessary. If entities with dispersed generation are registered as a Generator Owner (GO)/Generator Operator (GOP), it is the obligation of the registered entity to determine applicable standards and associated requirements and be able to explain how it complies accordingly. There is no need to modify the applicability of standards to specifically recognize dispersed generation as there is no recognizable reliability gap with the existing applicability of the standards included in this SAR.
No
See response to Question 1
See response to Question 1

Individual
David Jendras
Ameren
Yes
(1) The proposed SAR appears to advocate the GSU as the Element within these standards' applicability, which appears reasonable for a SAR. However, we believe that this conflicts with the BES Definition Phase 2 Reference figures. Our expectation is that the BES Definition would be included in the scope of this SAR.
Yes
Yes, we agree.
(1) Apply the Generator Site Boundary used in the BES Definition Reference (e.g. Figure I2-5) consistently for dispersed generation so that multiple GSU do not circumvent the 75MVA aggregate. (2) Develop a NERC Glossary definition for the term 'dispersed generation'.
Individual
Silvia Parada Mitchell
NextEra Energy
Agree
MidAmerican
Individual
Jonathan Meyer
Idaho Power
No
The BES definition in process has addressed the concerns raised in the SAR (in our opinion). Application of Standards applies to BES elements unless specifically excluded.
No
I see no need for a SAR.
No
N/A
N/A
Individual
Alice Ireland
Xcel Energy
Yes
We strongly support the objective of this SAR.
We believe that in addition to the approved standards mentioned in the SAR, NERC should communicate this issue directly to drafting teams working on active projects such as PRC-004-3 or PRC-027-1 to assure that they consider the applicability of their standard relative to dispersed generation and, if it is intended to include dispersed generation as in scope, to assure that correct terminology is used within their draft standard to avoid ambiguity and inconsistencies such as the SAR discusses for use of the term "main step up transformer" in FAC-008-3.

Individual
John Seelke
Public Service Enterprise Group
No
The SAR relies upon the phase 2 BES definition, as recently approved by the ballot body, but which has yet to be approved by the NERC Board or FERC. Under this definition, traditional generators at a site that exceed 75 MVA in aggregate as well as the all the equipment from terminals of each generator to the connection point with the BES are included in BES. Dispersed generators are treated differently. The individual dispersed generators are part of the BES if they are at a site where their aggregate nameplate capacity exceeds 75 MVA and they are connected to the BES; however, only equipment that delivers capacity from the point where those resources aggregate to greater than 75 MVA are included in the BES. Stated differently, traditional generators are contiguous with the BES, from the individual BES generators to their connection to the BES. Dispersed generators are not contiguous with the BES – the equipment that aggregate their output prior to it exceeding 75 MVA is excluded. These exclusions create a gap between dispersed BES generators and the BES they connect to. All generators should be treated comparably. The Eastern Interconnection Reliability Assessment Group (ERAG) manual supports our recommendation regarding inclusion equipment for dispersed generators. Wind farm modeling, as specified in the ERAG manual, (https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/MMWG%20Procedure%20Manual%20V10.pdf) requires a high level of detail – see p. 30, item 6, which states: “Wind Farms - Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs.” Thus, the ERAG manual requires modeling of non-BES Elements under phase 2 BES definition – see the BES Webinar slides nos. 5-7. (http://www.nerc.com/pa/Stand/WebinarLibrary/bes_phase2_third_posting_20131010_webinar_final.pdf) Setting aside our phase 2 definition concerns, the SAR does not make a coherent technical case for any standards changes. As an example, the justification for a change in PRC-005-2 has contradicting statements: “Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level.” In the first sentence, it appears that manufacturers install protection and control equipment at the “dispersed generation turbine and panel level,” yet the next sentence states that “it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level.” Which is it? During the balloting of PRC-005-2, no comments were submitted to the drafting team regarding the changes proposed in the SAR for PRC-005-2. Yet only a year after the final ballot on PRC-005-2, the SAR proposes changes to PRC-005-2 (and other standards) because the phase 2 definition, according to the SAR, would result in BES equipment at “dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES.” We believe that dispersed generators will have less equipment, not more, under the proposed BES definition because of the excluded equipment under that definition. Finally, there has been no justification put forth that would justify different treatment of dispersed generation from traditional generation. See our remarks in questions 2 and 6 below.
No
As stated previously, “small generators” (traditional versus dispersed) are not treated comparably in the phase 2 definition – traditional BES generators must be contiguous with the BES but dispersed generators need not be. While we would welcome changes that provide for comparable treatment for small generators, regardless of type, the unequal treatment embedded in the phase 2 definition must be corrected before those changes are considered.

No comments
No comments
No comments
Section 303 of the NERC ROP addresses “Relationship between Reliability Standards and Competition.” Item 1 states: “Competition — A Reliability Standard shall not give any market participant an unfair competitive advantage.” By not treating all generators comparably, the SAR violates item 1. Based upon this and our prior comments, we recommend that the SAR be rejected by the Standards Committee.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
No
The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011. Addtionally, these standards need to be listed: PRC-001/027 – Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 – In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many. PRC-019 – Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard. MOD 012/032 – In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many. MOD 025 & 026 and 027 – In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
Response from Q1: The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011. Addtionally, these standards need to be listed: PRC-001/027 – Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 – In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many. PRC-019 – Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard. MOD 012/032 – In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many. MOD 025 & 026 and 027 – In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.

Group
MRO NERC Standards Review Forum
Russel Mountjoy
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
The SAR does not specify what types of generation should be included for analysis as “dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
Chris Scanlon
Exelon
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
Yes, the SAR should focus on generation resources that are part of a facility that aggregates dispersed resources at 75 MVA or more. We believe the intent is to exclude individual units from certain requirements when those units do not meet the reporting criteria but are part of a facility that aggregates those units at the BES voltage level. We note that the question may lead to confusion. As written the use of "or" appears to be implying there is a choice between "dispersed generation" as used in the first clause of the question and some generation "types" (undefined but commonly understood to refer to fuel source) as used in the second clause. We do not believe the SAR should exclude generation based on fuel type.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is

recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate.
No
No
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
David Greyerbiehl
Consumers Energy Company
Yes
Yes
Yes
The SAR is required at a minimum, but a change to the BES definition is more appropriate. From the comments below submitted during the BES, the BES definition should at minimum be modified to provide consistency between generating resources (I2) and dispersed power producing resources (I4). Generating resources are required to be 20MVA in order to be considered an BES element, while dispersed power producing resources have no size consideration as long as they meet the net total MVA. Consumers Energy has completed studies with an operating wind farms and the loss of individual resources makes no impact the BES. The addition of individual resources does not make improve reliability as they have no effect on the system. The SAR intention is to modify the individual standards to define the requirements for all the additional BES elements that are being added that are not presently addressed in the standards or are against the manufacturers recommendations. While this approach can be used, and is required if the BES definition is not changed. A better method would be to include dispersed power producing resources at a point in which the total affects the BES and not as individual units. Previous Comments on BES definition: The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency. If and when Distributed Generation gains saturation is it our intent that whole neighborhoods or industrial parks be considered BES resources? Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. We can support the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with this definition as proposed, that is simply not the case.
No
No
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
Yes
Yes

Small generators that do not meet the individual 20 MVA criteria and are not part of the aggregated 75 MVA group that meets the BES inclusion criteria are not regarded BES facilities and therefore do not need to be addressed by this SAR. The scope therefore does not need to be expanded to all small generators.
Yes
No
No
No
Individual
Gary Kruempel
MidAmerican Energy Company
These comments were developed by NextERA (contact Brian Murhpy), MidAmerican, and Exelon
Yes
The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
Yes
The SAR does not specify what types of generation should be included for analysis as “dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
No
No
The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
yes
No. The City of Tallahassee is not aware of other business practices to be included.
No. The City of Tallahassee is not aware of such.

No.
Group
ACES Standards Collaborators
Ben Engelby
Yes
We find this SAR timely and necessary to avoid confusion in the application of the revised definition of the Bulk Electric System.
No
No, we do not agree that the scope of the SAR should be limited. The scope of the SAR should be to review standards applicable to GO/GOP and to limit the applicability based on the revised definition of the BES. Small generation regardless of type should be included in this review.
We agree with the list of standards to be reviewed. We would like to see flexibility in the scope of standards to be reviewed in the event that another standard is added during the standards development phase.
No.
No.
No other concerns.
Group
Duke Energy
Michael Lowman
Yes
Yes
(1) Duke Energy agrees that the scope of the SAR should be limited to Disperse Generation only.
(1) PRC-004-WECC-1 should also be included in this SAR with the same justification provided for the NERC Standard PRC-004-2
(1) Duke Energy is concerned that Dispersed Generation will have to be compliant with the BES definition Phase 1 prior to the Implementation of this Project and the implementation of Phase 2 of the BES definition. (2) Financial implications to registered entities should be considered and included in the Industry Need section of the SAR such as additional human resources required to maintain compliance if the standards are not revised for the applicability of dispersed generation resources at the point of aggregation to 75 MVA or greater.
Group
DTE Electric
Kathleen Black
Yes
Yes
Yes As stated in the background information, any relevant standard should be revised as necessary to insure that it is being applied at the point of aggregation.
No
No
No
Individual

Scott Langston
City of Tallahassee
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
Yes
No
No
No
Individual
Carla L. Holly
BP Wind Energy North America Inc.
Yes
Yes
The scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources as dispersed generation resources are unique and have operational characteristics that are not similar to most conventional generators, including generators that are considered to be classified as small.
Yes. We agree with the list of standards to be reviewed; however, we suggest more clarification about which specific IRO, MOD, PRC, and TOP standards would be considered as the SAR currently lists these categories generically.
No.
No.
No.
Individual
Karen Webb
City of Tallahassee
Yes
Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Yes
Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as waste-to-energy, biogas, and biomass generation sources.
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson

Yes
No
We believe the scope should include consideration of changes to standards applicability for all small generation. In particular, individual generators < 75 MVA should be exempted from model validation requirements unless transmission planning studies demonstrate such individual generators are critical to BES reliability. This would significantly reduce the compliance burdens being imposed on many GOs and GOPs and improve the focus on generators that are critical to reliability.
No. Need to also add those included in the Generator Verification Standard suite, including PRC-019, PRC-024, MOD-025, MOD-026, MOD-027. We are concerned with how certain standard requirements such as VAR-002 R3 can be applied to facilities with multiple “mini” units operating in parallel. For example, in the case of small turbine-generators one or more units operating in manual regulator mode would not have the same impact to the BES as a single large unit. Similar issues exist when some of the other listed standard requirements are applied such as model validation of excitation systems and governors (MOD-026 & MOD-027, as noted above).
No
No
No
Individual
Peter A. Heidrich
Florida Reliability Coordinating Council, Inc.
No
The SAR should not be limited to dispersed power producing resources only. A significant issue that will prove to derail this project is the potential inequitable treatment of generation. The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. Provisions with in the 'Applicability' of the appropriate Reliability Standards that take into account these types of units would significantly reduce the compliance obligations for units that simply are replaced (in whole)when a failure occurs.
No
The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. The reliability benefit of a generating facility is based on the MVA output of the unit, not on the fuel source or the prime mover force. Within a generating facility that aggregates to >75 MVA, there is no difference in the reliability benefit of a single wind turbine or a single gas fired turbine with the same MVA nameplate rating.
No
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
No
(a) BPA feels that the term “dispersed generation resource” is typically associated with facilities that produce electric power through cogeneration and through renewable resources — such as biomass, solar, hydro, wind, municipal waste, tidal, wave, geothermal, and energy storage. It doesn’t matter which type of resource is used to generate power; what matters is the aggregated output at the

point of interconnection, which may have an effect on the electric power system. IEEE Standard 1001-1988 (IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems) and IEEE Standard 1547 (IEEE Standard for Interconnecting distributed Resources with Electric Power Systems) provide information regarding the technical aspects of dispersed generation resources. (b) BPA feels that for PRC-005 & PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. It serves no reliability purpose if each turbine internally trips for a system event that requires continuation of the generation in a coordinated manner. (c) BPA feels that FAC-008 requires documentation from the generator to the high side of the main step-up transformer. For dispersed generation, this is the transformer at the main collector transformer. The SAR needs to consider including documentation for the collector system capability. BPA has found that when reactive current was not considered in earlier projects, overloads on some collectors were possible, which limited response to system events. (d) BPA has been requiring a collector system study provided by the generator owner to determine the reactive losses of the generation project and to ensure that reactive requirements are met. BPA has recently developed a collector system performance requirement to demonstrate compliance with reactive capability requirements. BPA recommends that this be added to the scope of the SAR to ensure that the generation in aggregate responds as required for a BES generation project.
No. BPA feels that a review of PRC-024 (Generator Frequency and Voltage Protective Relay Settings) needs to be included in the scope of this SAR. Aggregated dispersed generation must be able to ride-through faults and system disturbances the same as other generation resources.
No.
No.
Yes. IRO, MODs TOPs should be reported in aggregate. Outage coordination requirements for non-dispatchable generation should be eased as the certainty of the generation is never precisely known. BPA feels focusing compliance activities at the point of aggregation to 75 MVA is acceptable; however, there are a couple areas where we need to be cautious. One area of concern is the issue of back feed. Regardless of the size of the dispersed generation resource, proper precautions must be in place to ensure that it does not unintentionally or unexpectedly feed back into the BES. This is a matter of safety for personnel who might be doing construction or maintenance activities on the BES. BPA's other area of concern is the ability of the dispersed resources to ride through faults and system disturbances. BPA's concern here is similar to the concern BPA had when large amounts of wind generation began to be integrated into the grid. Specifically, BPA is concerned that the settings on protection schemes might be set such that large numbers of them would drop off during an event. This would be the equivalent of a large, high-speed spike in load, which could make the event far worse.

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standards drafting team (SDT) thanks all commenters who submitted comments on the Standard Authorization Request (SAR) for this project. The SAR was posted for a 30-day formal comment period from November 20, 2013 through December 19, 2013. Stakeholders were asked to provide feedback on the SAR through a special electronic comment form. There were 28 sets of comments, including comments from approximately 98 different commenters from approximately 60 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the DGR project page.

The DGR SDT has carefully reviewed and considered each stakeholder comment in developing this summary response. In addition, the DGR SDT notes that it will not propose changes to the SAR because it believes the objectives of this project can be adequately addressed within the scope of the SAR.

1. General Scope and Objective of the SAR

Some commenters disagree with the scope and objective of the SAR because they believe, for example, that the Bulk Electric System (BES) definition has addressed the concerns raised in the SAR, and that the SAR is therefore not necessary. The DGR SDT disagrees. While the BES definition has identified certain dispersed power producing resources and their aggregating equipment relative to their inclusion as BES Facilities, it does not take into account that in order to maintain reliability of the BES and ensure appropriate use by entities of compliance and maintenance resources, certain reliability standards and their requirements should not or cannot be applied to dispersed generating facilities in the same manner as traditional generating resources. The SAR is therefore necessary to ensure that the facilities of dispersed generation resources are appropriately assigned responsibility for requirements that actually impact the reliability of the BES, as the characteristics of operating dispersed generation can be unique.

Some commenters would like to include standards not specifically identified in the SAR, for example, certain CIP, FAC, IRO, MOD, PRC, and TOP standards. The DGR SDT agrees that all NERC Standards should be reviewed as part of this project to determine whether changes are justified in order to account for the unique characteristics of dispersed generation, and has undertaken such a review. This review includes standards that are directly applicable to dispersed generation resources. For many standards, the concerns related to applicability to dispersed generation may be resolved through the publication of NERC guidance documentation in lieu of changes to the language of existing or future reliability standards. The DGR SDT expects that the concerns with the majority of the standards will be addressed through this manner.

Some commenters note that the scope of the SAR should be expanded to include all small generators regardless of types. As noted in the SAR, the DGR SDT will consider those resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a collector system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. The DGR SDT believes that the scope of the current SAR allows for consideration of various generation designs when determining their impact upon the reliability of the BES. However, the DGR SDT notes that the impact that dispersed power producing resources (as described in the BES Definition reference document) could potentially have on the reliability of the BES is not necessarily the same impact that a traditional generator, regardless of size, will have, and must account for these differences when considering the applicability of any specific standard requirements.

At least one commenter suggested that for PRC-005 and PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. The DGR SDT understands that there are certain reliability standards that may require applicability on Facilities below the point of aggregation at 75 MVA nameplate rating and is considering these functions in reviewing the applicability of specific requirements.

At least one commenter stated that the SAR does not make a coherent technical case for any standards changes. The DGR SDT will evaluate the merits of any proposed changes to the standards within the scope of the SAR and will seek to provide a detailed justification for proposed changes.

At least one commenter made suggestions to improve clarity of the SAR, e.g., changes to the “Industry Need” and “SAR Information” sections of the SAR. The DGR SDT will take those comments into account during the evaluation process to address the goals of this project and the revisions that are recommended.

The DGR SDT acknowledges that a number of comments support the initial scope of the SAR, with some additional recommendations regarding applicability. The DGR SDT feels that the scope of the current SAR allows for consideration of various generation designs when determining their impact upon the reliability of the BES.

2. BES Definition and Transition Period

At least one commenter expressed concern about the transition period for implementation of the BES definition and this project. The DGR SDT gives due consideration to the timing associated with compliance requirements to include transition periods. This will encompass the transitional period associated with the BES definition.

The DGR SDT notes that the project schedule has been developed to take into account the July 1, 2016 compliance obligation date associated with the revised BES definition.

The DGR SDT also notes that it is focused on reliability in evaluating the standards but will remain mindful of the financial implications of compliance.

Some commenters suggest that the BES definition should be revised. The DGR SDT will not re-evaluate the BES definition, as it is beyond the scope of this project. The goal of the SAR is to revise the applicability of GO/GOP Reliability Standards or the applicability of requirements in GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the revised definition of the BES.

3. Canadian Provincial or other Regulatory Requirements

At least one commenter stated that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project. The DGR SDT can make recommendations to Regional Entities that have approved Regional Reliability Standards; however, the DGR SDT cannot change those regional standards. Responsible entities may in fact be subject to additional regulatory requirements but such requirements are outside of NERC's sanctioned enforcement authorities and cannot be addressed in this process, but may be considered.

At least one commenter raised concerns about Quebec registration requirements. The DGR SDT does not believe it needs to specifically address the registration criteria of Canadian provinces. Although Quebec has unique registration values, it should not impact standard applicability.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you may contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

NERC

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Jeffrey Delgado	Caithness Shepherds Flat, LLC					X					
No Additional Responses													
2.	Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
No Additional Responses													
3.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
3.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
4.	Mike Kidwell	Empire District Electric	SPP	1
5.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
6.	Shannon Mickens	Southwest Power Pool	SPP	2
7.	Katy Onnen	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
26.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Russel Mountjoy	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Chuck Wicklund	OtterTail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madision Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	Midcontinent Independent System Operator	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
14.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kathleen Goodman	ISO-NE	NPCC	2
2.	Cheryl Moseley	ERCOT	ERCOT	2
3.	Al DiCaprio	PJM	RFC	2
4.	Terry Bilke	MISO	MRO	2
5.	Charles Yeung	SPP	SPP	2
6.	Ben Li	IESO	NPCC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4
2.	Alisha Anker	Prairie Power, Inc.	SERC	3
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
5.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Regulated Marketing	RFC	5
4.	Barbara Holland		RFC	
5.	Neil Kennings		RFC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Wayne Johnson	Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Anasis	Transmission Technical Operations	WECC	1
2.	Richard Becker	Transmission Substation Engineering	WECC	1
3.	Stephen Enyeart	Transmission Customer Service Engineering	WECC	1
4.	Fred Ojima	Transmission Planning	WECC	1
5.	Chuck Sheppard	Transmission Vegetation/Access Road Mgmt	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
13.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Individual	Patricia Metro	National Rural Electric Cooperative Association	X		X	X						
15.	Individual	David Jendras	Ameren	X		X	X	X					
16.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
17.	Individual	Jonathan Meyer	Idaho Power	X									
18.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
19.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
20.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
21.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
22.	Individual	David Greyerbiehl	Consumers Energy Company			X		X					
23.	Individual	Gary Kruempel	MidAmerican Energy Company	X		X		X	X				
24.	Individual	Bill Fowler	City of Tallahassee (TAL)			X							
25.	Individual	Scott Langston	City of Tallahassee	X									
26.	Individual	Carla L. Holly	BP Wind Energy North America Inc.					X					
27.	Individual	Karen Webb	City of Tallahassee					X					
28.	Individual	Peter A. Heidrich	Florida Reliability Coordinating Council, Inc.										X

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Agree	Supporting Comments of "Entity Name"
NextEra Energy	Agree	MidAmerican
MidAmerican Energy Company		These comments were developed by NextERA (contact Brian Murhpy), MidAmerican, and Exelon

1. **Do you agree with the scope and objectives of this SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 1 Comment
National Rural Electric Cooperative Association	No	NRECA does not believe this SAR is necessary. If entities with dispersed generation are registered as a Generator Owner (GO)/Generator Operator (GOP), it is the obligation of the registered entity to determine applicable standards and associated requirements and be able to explain how it complies accordingly. There is no need to modify the applicability of standards to specifically recognize dispersed generation as there is no recognizable reliability gap with the existing applicability of the standards included in this SAR.
Idaho Power	No	The BES definition in process has addressed the concerns raised in the SAR (in our opinion). Application of Standards applies to BES elements unless specifically excluded.
Public Service Enterprise Group	No	The SAR relies upon the phase 2 BES definition, as recently approved by the ballot body, but which has yet to be approved by the NERC Board or FERC. Under this definition, traditional generators at a site that exceed 75 MVA in aggregate as well as the all the equipment from terminals of each generator to the connection point with the BES are included in BES. Dispersed generators are treated differently. The individual dispersed generators are part of the BES if they are at a site where their aggregate nameplate capacity exceeds 75 MVA and they are connected to the BES; however, only equipment that delivers capacity from the point where those resources aggregate to greater than 75 MVA are included in the BES. Stated differently, traditional generators are contiguous with the BES, from the individual BES generators to their connection to the BES. Dispersed generators are not contiguous with the BES - the equipment that aggregate their output prior to it exceeding 75 MVA is excluded. These exclusions create a gap between dispersed BES generators and the BES they connect to. All generators should be treated comparably. The Eastern Interconnection Reliability

Organization	Yes or No	Question 1 Comment
		Assessment Group (ERAG) manual supports our recommendation regarding inclusion equipment for dispersed generators. Wind farm modeling, as specified in the ERAG manual, (https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/MMWG%20Procedure%20Manual%20V10.pdf) requires a high level of detail - see p. 30, item 6, which states: "Wind Farms - Include all 34.5 kV collector bus(es) and the main facility step-up transformer(s) from 34.5 kV to transmission voltage, as well as one 0.600 kV (or whatever the wind generator nominal voltage is) level bus off each collector bus with a lumped generator and lumped GSU representing the aggregate of the wind turbines attached to that collector bus and their GSUs." Thus, the ERAG manual requires modeling of non-BES Elements under phase 2 BES definition - see the BES Webinar slides nos. 5-7. (http://www.nerc.com/pa/Stand/WebinarLibrary/bes_phase2_third_posting_20131010_webinar_final.pdf) Setting aside our phase 2 definition concerns, the SAR does not make a coherent technical case for any standards changes. As an example, the justification for a change in PRC-005-2 has contradicting statements: "Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level." In the first sentence, it appears that manufacturers install protection and control equipment at the "dispersed generation turbine and panel level," yet the next sentence states that "it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level." Which is it?During the balloting of PRC-005-2, no comments were submitted to the drafting team regarding the changes proposed in the SAR for PRC-005-2. Yet only a year after the final ballot on PRC-005-2, the SAR proposes changes to PRC-005-2 (and other standards) because the phase 2 definition, according to the SAR, would result in BES equipment at "dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES." We believe that dispersed generators will have less equipment, not more, under the proposed BES definition because of the excluded equipment under that definition. Finally, there has been no justification put forth that would justify different

Organization	Yes or No	Question 1 Comment
		treatment of dispersed generation from traditional generation. See our remarks in questions 2 and 6 below.
Wisconsin Electric Power Company	No	The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011.Addtionally, these standards need to be listed:PRC-001/027 - Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 - In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many.PRC-019 - Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard.MOD 012/032 - In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many.MOD 025 & 026 and 027 - In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
Florida Reliability Coordinating Council, Inc.	No	The SAR should not be limited to dispersed power producing resources only. A significant issue that will prove to derail this project is the potential inequitable treatment of generation. The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. Provisions with in the 'Applicability' of the appropriate Reliability Standards that take

Organization	Yes or No	Question 1 Comment
		into account these types of units would significantly reduce the compliance obligations for units that simply are replaced (in whole)when a failure occurs.
ACES Standards Collaborators	Yes	We find this SAR timely and necessary to avoid confusion in the application of the revised definition of the Bulk Electric System.
MRO NERC Standards Review Forum	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
American Electric Power	Yes	AEP would prefer that the solution for applicability of dispersed generation at the turbine or generating unit level would be by adjusting the BES definition accordingly. Creating a new SAR, allowing this topic be discussed within the framework of the BES definition itself, would seem the most direct and efficient way of debating the topic. However, if that cannot be accomplished, AEP supports the effort of this SAR as an alternative (though less desirable) means to accomplish the same goal.
Ameren	Yes	(1) The proposed SAR appears to advocate the GSU as the Element within these standards' applicability, which appears reasonable for a SAR. However, we believe that this conflicts with the BES Definition Phase 2 Reference figures. Our expectation is that the BES Definition would be included in the scope of this SAR.
Xcel Energy	Yes	We strongly support the objective of this SAR.
Exelon	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.

Organization	Yes or No	Question 1 Comment
MidAmerican Energy Company	Yes	The SAR indicates several standards that should be considered for modification for dispersed generating units. It also provides for examination of other standards that may need to be similarly modified to accommodate the unique aspects of dispersed generation. In addition the SAR provides an explanation of which types of generation are to be reviewed in this project and this explanation is appropriate to define the scope of the project.
City of Tallahassee (TAL)	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
City of Tallahassee	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
City of Tallahassee	Yes	Should the 75MVA be differentiated for Solar PV and other generating units that have both a DC and AC rating?
Caithness Shepherds Flat, LLC	Yes	
Arizona Public Service Company	Yes	
SPP Standards Review Group	Yes	
Northeast Power Coordinating Council	Yes	
ISO/RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
DTE Electric	Yes	
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Bonneville Power Administration	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
BP Wind Energy North America Inc.	Yes	

2. Do you agree that the scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources, or should the scope encompass consideration of changes to standards applicability for all small generation regardless of type? Please provide a technical rationale for your response.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	Scope should expanded to include all small generators regardless of types. There is no specific reason to not include all. Generally, there is little reliability benefits to BES by applying NERC standards to small generators regardless of the type.
SPP Standards Review Group	No	We believe that this evaluation should be extended to all small generation regardless of type because the impact on the BES would be the same regardless of the source or prime mover of the generation.
ACES Standards Collaborators	No	No, we do not agree that the scope of the SAR should be limited. The scope of the SAR should be to review standards applicable to GO/GOP and to limit the applicability based on the revised definition of the BES. Small generation regardless of type should be included in this review.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No	We believe the scope should include consideration of changes to standards applicability for all small generation. In particular, individual generators < 75 MVA should be exempted from model validation requirements unless transmission planning studies demonstrate such individual generators are critical to BES reliability. This would significantly reduce the compliance burdens being imposed on many GOs and GOPs and improve the focus on generators that are critical to reliability.

Organization	Yes or No	Question 2 Comment
Generation and Energy Marketing		
Bonneville Power Administration	No	(a) BPA feels that the term "dispersed generation resource" is typically associated with facilities that produce electric power through cogeneration and through renewable resources - such as biomass, solar, hydro, wind, municipal waste, tidal, wave, geothermal, and energy storage. It doesn't matter which type of resource is used to generate power; what matters is the aggregated output at the point of interconnection, which may have an effect on the electric power system. IEEE Standard 1001-1988 (IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems) and IEEE Standard 1547 (IEEE Standard for Interconnecting distributed Resources with Electric Power Systems) provide information regarding the technical aspects of dispersed generation resources.(b) BPA feels that for PRC-005 & PRC-023, the SAR needs to include individual turbine equipment dynamic response, such that the aggregate collector system provides the required relay response, not just the protective devices from the point of aggregation. It serves no reliability purpose if each turbine internally trips for a system event that requires continuation of the generation in a coordinated manner.(c) BPA feels that FAC-008 requires documentation from the generator to the high side of the main step-up transformer. For dispersed generation, this is the transformer at the main collector transformer. The SAR needs to consider including documentation for the collector system capability. BPA has found that when reactive current was not considered in earlier projects, overloads on some collectors were possible, which limited response to system events.(d) BPA has been requiring a collector system study provided by the generator owner to determine the reactive losses of the generation project and to ensure that reactive requirements are met. BPA has recently developed a collector system performance requirement to demonstrate compliance with reactive capability requirements. BPA recommends that this be added to the scope of the SAR to ensure that the generation in aggregate responds as required for a BES generation project.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	We believe it is preferable, at least initially, for the scope to remain limited to dispersed generation resources.
National Rural Electric Cooperative Association	No	See response to Question 1
Idaho Power	No	I see no need for a SAR.
Public Service Enterprise Group	No	As stated previously, “small generators” (traditional versus dispersed) are not treated comparably in the phase 2 definition - traditional BES generators must be contiguous with the BES but dispersed generators need not be. While we would welcome changes that provide for comparable treatment for small generators, regardless of type, the unequal treatment embedded in the phase 2 definition must be corrected before those changes are considered.
Florida Reliability Coordinating Council, Inc.	No	The scope should include all small generators regardless of fuel source or prime mover force. The scope should further identify small package style units that are typically considered 'run to fail' units. The reliability benefit of a generating facility is based on the MVA output of the unit, not on the fuel source or the prime mover force. Within a generating facility that aggregates to >75 MVA, there is no difference in the reliability benefit of a single wind turbine or a single gas fired turbine with the same MVA nameplate rating.
Caithness Shepherds Flat, LLC	Yes	Caithness Shepherds Flat Wind Farm (CSF), located in Oregon, supports the SAR as written and believes the scope should address dispersed generation resources with collector systems only. In the development of CSF’s NERC compliance program, it became apparent that some GO/GOP applicable Reliability Standards were written with fossil fuel facilities in mind, and not generation resources such as wind. The VAR-002 standard for example, requiring reactive and voltage control of individual generators and notification of the TOP when there is a change in status, would appear to be irrelevant to the TOP, but rather the aggregate MW output at the point

Organization	Yes or No	Question 2 Comment
		of interconnection should be what is relevant. CSF's wind farm consists of several hundred wind turbines, all < 3 MW in nameplate capacity. The TOP does not need to be notified about individual turbine voltage status, as any loss of voltage control of an individual turbine will not be detected by the TOP. The relevant factor is in the voltage at the point of interconnection which is controlled by a "Wind Farm Management System" WFMS voltage control system. Change in status of the WFMS would be of interest to the TOP, so the standard should allow for this variance.
MRO NERC Standards Review Forum	Yes	The SAR does not specify what types of generation should be included for analysis as "dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
ISO/RTO Council Standards Review Committee	Yes	Small generators that do not meet the individual 20 MVA criteria and are not part of the aggregated 75 MVA group that meets the BES inclusion criteria are not regarded BES facilities and therefore do not need to be addressed by this SAR. The scope therefore does not need to be expanded to all small generators.
Duke Energy	Yes	(1) Duke Energy agrees that the scope of the SAR should be limited to Disperse Generation only.
MidAmerican Energy Company	Yes	The SAR does not specify what types of generation should be included for analysis as "dispersed generation resources. It only refers to those that are a part of a facility that aggregates to 75 MVA or more. As written the SAR is not limited to any particular type of small generation. Under the SAR all types could and should be considered for revision.
City of Tallahassee (TAL)	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.

Organization	Yes or No	Question 2 Comment
City of Tallahassee	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as WTE, biogas and biomass generation sources.
BP Wind Energy North America Inc.	Yes	The scope of the SAR should be limited to considering revisions necessary to address the unique technical and reliability aspects of dispersed generation resources as dispersed generation resources are unique and have operational characteristics that are not similar to most conventional generators, including generators that are considered to be classified as small.
City of Tallahassee	Yes	Dispersed generation should include intermittent power sources such as wind and solar, but also non-intermittent such as waste-to-energy, biogas, and biomass generation sources.
Exelon	Yes	Yes, the SAR should focus on generation resources that are part of a facility that aggregates dispersed resources at 75 MVA or more. We believe the intent is to exclude individual units from certain requirements when those units do not meet the reporting criteria but are part of a facility that aggregates those units at the BES voltage level. We note that the question may lead to confusion. As written the use of "or" appears to be implying there is a choice between "dispersed generation" as used in the first clause of the question and some generation "types" (undefined but commonly understood to refer to fuel source) as used in the second clause. We do not believe the SAR should exclude generation based on fuel type.
DTE Electric	Yes	
Manitoba Hydro	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	

3. Do you agree with the list of standards to be reviewed? If you do not agree, please note specific standards you think should be added to or removed from the list.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 3 Comment
American Electric Power	Every standard that involves the GO and/or GOP should be included in the scope of the SAR. This does not imply that all standards should be modified, but the SDT and commenters should be afforded the opportunity to consider the impacts of such changes. For example, PRC-024, PRC-001, CIP-002 through CIP-011, etc. should be considered.
Public Service Enterprise Group	No comments
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No. Need to also add those included in the Generator Verification Standard suite, including PRC-019, PRC-024, MOD-025, MOD-026, MOD-027. We are concerned with how certain standard requirements such as VAR-002 R3 can be applied to facilities with multiple “mini” units operating in parallel. For example, in the case of small turbine-generators one or more units operating in manual regulator mode would not have the same impact to the BES as a single large unit. Similar issues exist when some of the other listed standard requirements are applied such as model validation of excitation systems and governors (MOD-026 & MOD-027, as noted above).
Bonneville Power Administration	No. BPA feels that a review of PRC-024 (Generator Frequency and Voltage Protective Relay Settings) needs to be included in the scope of this SAR. Aggregated dispersed generation must be able to ride-through faults and system disturbances the same as other generation resources.

Organization	Question 3 Comment
Wisconsin Electric Power Company	Response from Q1:The SAR needs to include applicability to CIP-002-5, proposed for the identification of BES Cyber Assets and BES Cyber Systems. If individual wind turbines are included in the BES, those cyber assets which support their operation (monitoring and control functions local to each turbine) would become BES Cyber Systems subject to some level of compliance requirements of the CIP v5 standards. The SAR needs to include all the CIP version 5 standards, including CIP-010 and CIP-011.Addtionally, these standards need to be listed:PRC-001/027 - Coordination for distributed resources needs to be accomplished with the collector system of the distributed resource, not with the transmission system. The collector system needs to be coordinated with the transmission system, however, the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. PRC-024 - In most cases most distributed resources are many identical units. It would seem reasonable to document the relay data for one unit and then use it for many.PRC-019 - Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The PRC-019 standard should be modified to allow coordination with this type of control for dispersed generation facilities under the requirements of the standard.MOD 012/032 - In most cases most distributed resources are many identical units. It would seem reasonable to provide an example model of one resource and then use it for many.MOD 025 & 026 and 027 - In most cases most distributed resources are many identical units. It would seem reasonable to validate one unit and then use the results for many.
National Rural Electric Cooperative Association	See response to Question 1
MRO NERC Standards Review Forum	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The

Organization	Question 3 Comment
	reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
Exelon	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate.
MidAmerican Energy Company	The SAR provides a list of several specific standards application to Generator Owners and/or Generator Operators that would be reviewed as part of the project. In addition it proposes a review of several project families (IRO,MOD, PRC and TOP) that would be examined. The specific list is recommended as proposed in the SAR and with the flexibility to review other standards the list as indicated is appropriate Consideration should be given to an addition to the Attachment in CIP-002 to add an item that would exclude components below the 75MVA aggregation point. The reasoning would be parallel to the other standards addressed in the SAR where the aggregation point would be identified as the point at which the standard would apply. For CIP the result would be that the components below the aggregation point would not have to be addressed, i.e. they would not be high, medium, or low.
ACES Standards Collaborators	We agree with the list of standards to be reviewed. We would like to see flexibility in the scope of standards to be reviewed in the event that another standard is added during the standards development phase.
Xcel Energy	We believe that in addition to the approved standards mentioned in the SAR, NERC should communicate this issue directly to drafting teams working on active projects such as PRC-004-3 or PRC-027-1 to assure that they consider the applicability of their standard relative to dispersed generation and, if it is intended to include dispersed generation as in scope, to assure that correct

Organization	Question 3 Comment
	terminology is used within their draft standard to avoid ambiguity and inconsistencies such as the SAR discusses for use of the term "main step up transformer" in FAC-008-3.
SPP Standards Review Group	While we may agree with the list of standards as presented in the SAR we would encourage the SAR drafting team to not limit itself to just those particular standards. For example, once a drafting team is established and work begins on the project, we don't want the project to be limited by the scope as currently defined in the SAR. We need to factor in some flexibility to go beyond this specific list to capture all those standards/requirements/definitions which may be impacted in this review.
Caithness Shepherds Flat, LLC	Yes
Arizona Public Service Company	Yes
ISO/RTO Council Standards Review Committee	Yes
Consumers Energy Company	Yes
City of Tallahassee (TAL)	yes
City of Tallahassee	Yes
Ameren	Yes, we agree.
Northeast Power Coordinating Council	Yes.

Organization	Question 3 Comment
BP Wind Energy North America Inc.	Yes. We agree with the list of standards to be reviewed; however, we suggest more clarification about which specific IRO, MOD, PRC, and TOP standards would be considered as the SAR currently lists these categories generically.
DTE Electric	YesAs stated in the background information, any relevant standard should be revised as necessary to insure that it is being applied at the point of aggregation.

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this SAR should it move forward? If yes, please identify the business practice.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 4 Comment
Caithness Shepherds Flat, LLC	No
Arizona Public Service Company	No
ISO/RTO Council Standards Review Committee	No
DTE Electric	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No
Manitoba Hydro	No

Organization	Question 4 Comment
Idaho Power	No
Exelon	No
MidAmerican Energy Company	No
City of Tallahassee	No
Florida Reliability Coordinating Council, Inc.	No
Public Service Enterprise Group	No comments
Northeast Power Coordinating Council	No.
ACES Standards Collaborators	No.
Bonneville Power Administration	No.
American Electric Power	No.
BP Wind Energy North America Inc.	No.
City of Tallahassee (TAL)	No. The City of Tallahassee is not aware of other business practices to be included.
SPP Standards Review Group	Not at this time.

Organization	Question 4 Comment
Consumers Energy Company	The SAR is required at a minimum, but a change to the BES definition is more appropriate.From the comments below submitted during the BES, the BES definition should at minimum be modified to provide consistency between generating resources (I2) and dispersed power producing resources (I4). Generating resources are required to be 20MVA in order to be considered an BES element, while dispersed power producing resources have no size consideration as long as they meet the net total MVA. Consumers Energy has completed studies with an operating wind farms and the loss of individual resources makes no impact the BES. The addition of individual resources does not make improve reliability as they have no effect on the system.The SAR intention is to modify the individual standards to define the requirements for all the additional BES elements that are being added that are not presently addressed in the standards or are against the manufacturers recommendations. While this approach can be used, and is required if the BES definition is not changed. A better method would be to include dispersed power producing resources at a point in which the total affects the BES and not as individual units.Previous Comments on BES definition:The inclusion and the clarification of the inclusion seem to contradict each other. The highlight portion above seems to indicate inclusion only from the point of aggregation of 75MVA or above. This, in most Wind Park cases would include a collector bus but probably not individual wind turbines. However I4 seems to indicate that the case of a Wind Park that has a total aggregation of 75 MVA, all associated equipment including every individual wild turbine would be included. There is inconsistency.If and when Distributed Generation gains saturation is it our intent that whole neighborhoods or industrial parks be considered BES resources? Technical justification should be needed to include resources in the BES, not the other way around. Is there a real expectation that a single collector circuit containing ten, 1.2MW wind turbines can cause cascading or uncontrollable outages of the surrounding system? It is extremely doubtful. We can support the inclusion of equipment where the aggregation of 75 MVA or more connects to the Bulk Electric System at voltages of 100kv or greater. There is a clear indication here that a single contingency can remove the total of the capacity from the system where with this definition as proposed, that is simply not the case.

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 5 Comment
SPP Standards Review Group	Although we are not aware of any specific federal regulatory requirements, the drafting team needs to keep in mind that there may be state regulatory requirements established for dispersed generation that may need to be considered in this project.
Idaho Power	N/A
Caithness Shepherds Flat, LLC	No
Arizona Public Service Company	No
ISO/RTO Council Standards Review Committee	No
DTE Electric	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation;	No

Organization	Question 5 Comment
Southern Company Generation and Energy Marketing	
Manitoba Hydro	No
Exelon	No
Consumers Energy Company	No
MidAmerican Energy Company	No
City of Tallahassee	No
Public Service Enterprise Group	No comments
ACES Standards Collaborators	No.
Bonneville Power Administration	No.
American Electric Power	No.
BP Wind Energy North America Inc.	No.
City of Tallahassee (TAL)	No. The City of Tallahassee is not aware of such.

Organization	Question 5 Comment
Northeast Power Coordinating Council	Yes.It must be considered that the operating system in Quebec follows chapter R-6.01 An Act Respecting the Regie de L'Energie, which details:(1) an owner or operator of a facility with a capacity of 44 kV or more connected to an electric power transmission system;(2) an owner or operator of an electric power transmission system;(3) an owner or operator of a production facility with a capacity of 50 megavolt amperes (MVA) or more connected to an electric power transmission system;(4) a distributor with a peak capacity of over 25 megawatts (MW), whose facilities are connected to an electric power transmission system; and(5) a person who uses an electric power transmission system under an electric power transmission service agreement with the electric power carrier or with any other carrier in QuÃ©bec.

6. **Are there any other concerns with this SAR that haven't been covered in previous questions?**

Summary Consideration: The DGR SDT thanks all commenters for their input and refers the reader to the summary response above.

Organization	Question 6 Comment
Arizona Public Service Company	No
Caithness Shepherds Flat, LLC	No
City of Tallahassee	No
Consumers Energy Company	No
DTE Electric	No
Florida Reliability Coordinating Council, Inc.	No
ISO/RTO Council Standards Review Committee	No
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	No

Organization	Question 6 Comment
Generation and Energy Marketing	
ACES Standards Collaborators	No other concerns.
American Electric Power	No.
City of Tallahassee (TAL)	No.
Northeast Power Coordinating Council	No.
BP Wind Energy North America Inc.	No.
SPP Standards Review Group	Regarding the July 2016 deadline, the drafting team needs to be sure that this effort is complete in time for the industry to be ready by July 2016. We need to be sure that as the deadline approaches, compliance preparations aren't made and then un-made as a result of a modification to an existing standard which is impacted by this effort.In the 1st line of the 1st paragraph of the Industry Need section under SAR Information, we suggest replacing 'application' with 'applicability'.In the 5th line of the 1st paragraph of the Brief Description section under SAR Information, replace 'real time' with 'Real-time', the NERC Glossary term.In the 1st line of the FAC-008-3 paragraph under SAR Information, hyphenate step-up.In the next to last line of the General review of IROs, MODs, PRCs, TOPs paragraph, change 'uneeded' to 'unneeded'.
Public Service Enterprise Group	Section 303 of the NERC ROP addresses "Relationship between Reliability Standards and Competition." Item 1 states: "Competition - A Reliability Standard shall not give any market participant an unfair competitive advantage." By not treating all generators comparably, the SAR violates item 1. Based upon this and our prior comments, we recommend that the SAR be rejected by the Standards Committee.

Organization	Question 6 Comment
Exelon	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
MRO NERC Standards Review Forum	The SAR includes the objective to complete the changes and obtain regulatory approval prior to the completion of the implementation of the BES definition. It is essential that this schedule is met so that dispersed generation owners and operators can plan and implement their compliance programs without having to temporarily implement requirements that will be superseded by this project.
Bonneville Power Administration	Yes. IRO, MODs TOPs should be reported in aggregate. Outage coordination requirements for non-dispatchable generation should be eased as the certainty of the generation is never precisely known.BPA feels focusing compliance activities at the point of aggregation to 75 MVA is acceptable; however, there are a couple areas where we need to be cautious. One area of concern is the issue of back feed. Regardless of the size of the dispersed generation resource, proper precautions must be in place to ensure that it does not unintentionally or unexpectedly feed back into the BES. This is a matter of safety for personnel who might be doing construction or maintenance activities on the BES.BPA's other area of concern is the ability of the dispersed resources to ride through faults and system disturbances. BPA's concern here is similar to the concern BPA had when large amounts of wind generation began to be integrated into the grid. Specifically, BPA is concerned that the settings on protection schemes might be set such that large

Organization	Question 6 Comment
	numbers of them would drop off during an event. This would be the equivalent of a large, high-speed spike in load, which could make the event far worse.
	(1) Apply the Generator Site Boundary used in the BES Definition Reference (e.g. Figure I2-5) consistently for dispersed generation so that multiple GSU do not circumvent the 75MVA aggregate.(2) Develop a NERC Glossary definition for the term ‘dispersed generation’.
Duke Energy	(1) Duke Energy is concerned that Dispersed Generation will have to be compliant with the BES definition Phase 1 prior to the Implementation of this Project and the implementation of Phase 2 of the BES definition.(2) Financial implications to registered entities should be considered and included in the Industry Need section of the SAR such as additional human resources required to maintain compliance if the standards are not revised for the applicability of dispersed generation resources at the point of aggregation to 75 MVA or greater.
Manitoba Hydro	Although we do not have any concerns with this SAR, we have the following suggestions to improve clarity.(1) Industry Need - remove the words “Bulk Electric System” from the second paragraph to leave only the acronym, BES because this is the second instance of BES in the document. (2) SAR Information - capitalize ‘misoperation’ because it appears in the Glossary of Terms.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-001-1.1(X)[1] is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-1.1(X)

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:**

   See the Implementation Plan for this standard.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

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

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

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

> Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

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

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

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator’s Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators’ Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

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

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

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

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

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

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
TBD (balloted as 1.1(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of requirements to BES dispersed power producing resources

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-001-1.1(X)[1] is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.
[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **System Protection Coordination**
2. **Number:** PRC-001-1.1(X)
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.
4. **Applicability**
   - **4.1.** Balancing Authorities
   - **4.2.** Transmission Operators
   - **4.3.** Generator Operators
5. **Effective Date:** ~~January 1, 2007~~

   See the Implementation Plan for this standard.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

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

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

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

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

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

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

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

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

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

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

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

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
TBD (balloted as 1.1(X))	TBD	Standard revised in Project 2014-01	Applicability revised to clarify application of requirements to BES dispersed power producing resources

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Given the timing of concurrent standards development of PRC projects, PRC-019-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-019. If this occurs, PRC-019-2 will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

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

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

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

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

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

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

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

4.2.3.1 This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual unit level, the SDT believes that coordination should take place at the individual power producing resource level. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

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

5. Effective Date:

See the Implementation Plan for this standard.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

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

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

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

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable

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

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

Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

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

E. Regional Variances

None.

F. Associated Documents

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

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

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

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

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

Version History

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

G. Reference

Examples of Coordination

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

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

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

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

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

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

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

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

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

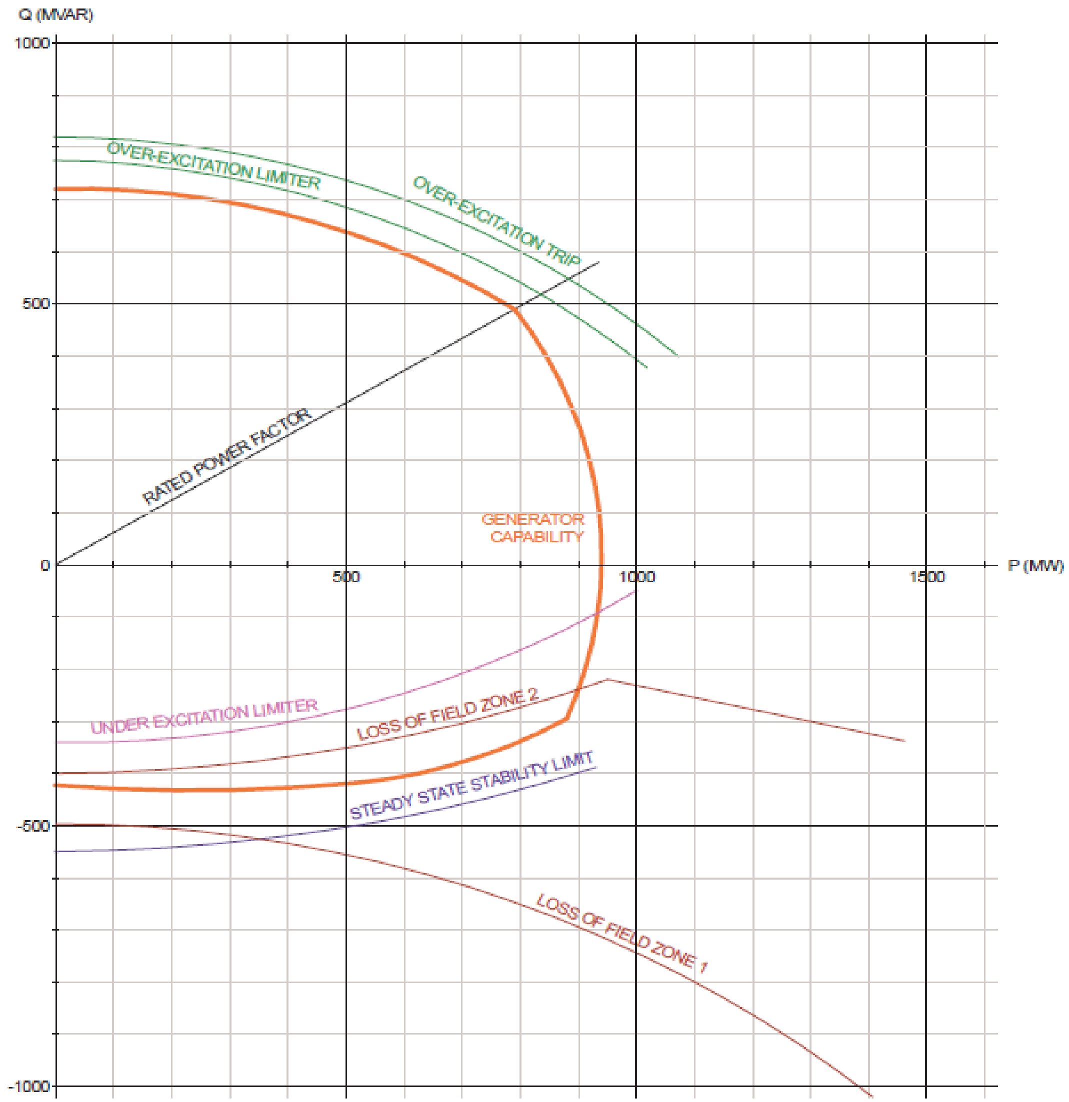
$$R = V^2{}_g/2*(1/X_s+1/X_d)$$

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

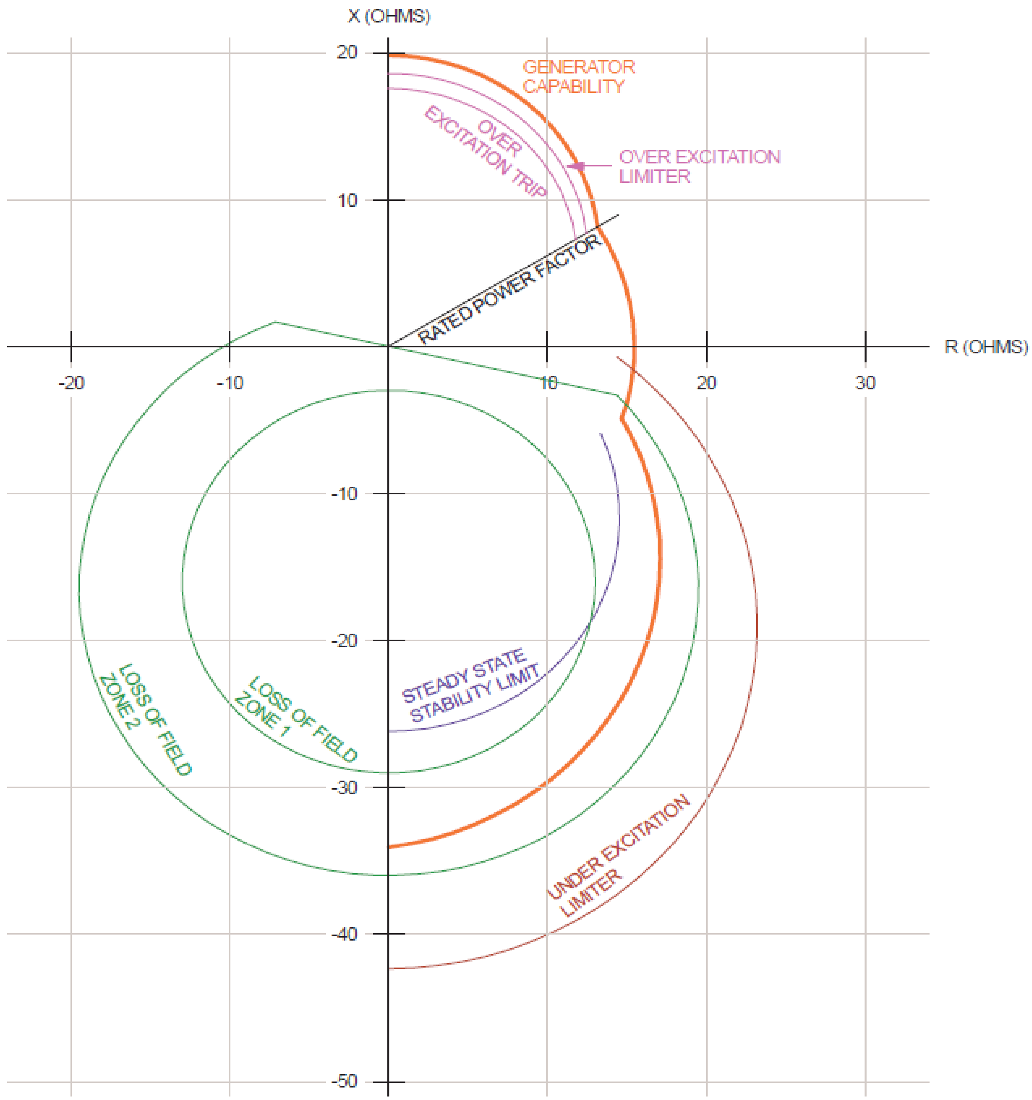
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

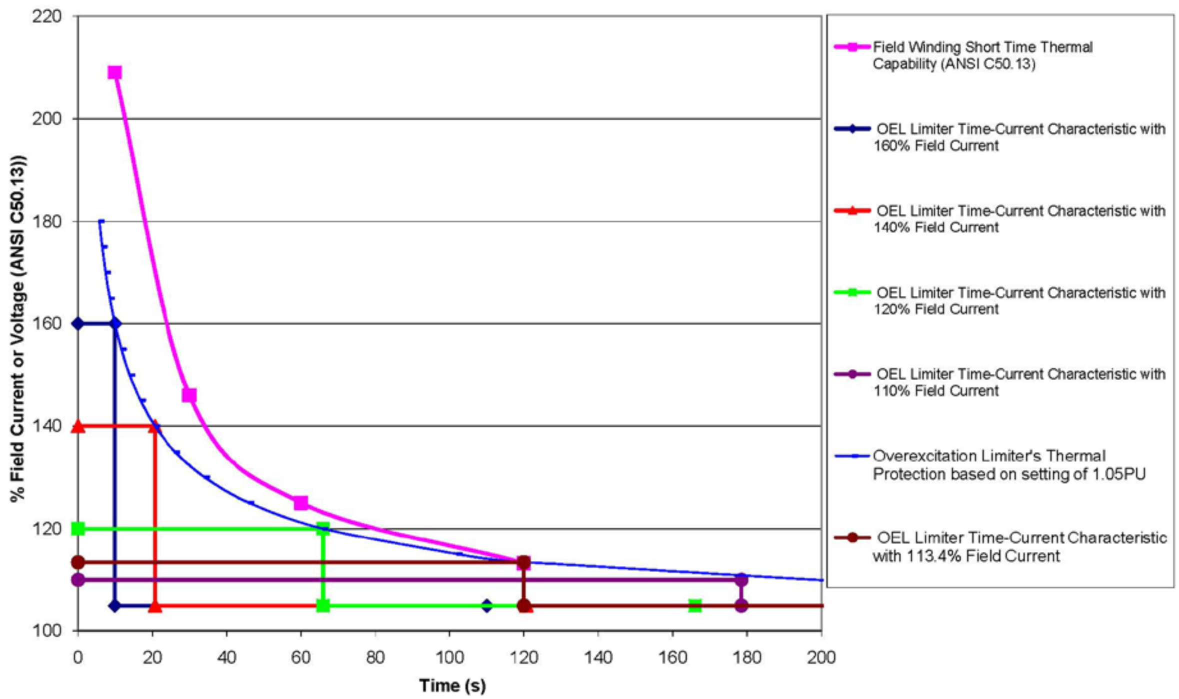
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Given the timing of concurrent standards development of PRC projects, PRC-019-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-019. If this occurs, PRC-019-2 will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

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

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

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

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

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

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

4.2.3.1 This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual unit level, the SDT believes that coordination should take place at the individual power producing resource level. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

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

5. Effective Date:

See the Implementation Plan for this standard.

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

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

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

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

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

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

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

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

~~**5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator~~

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

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

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

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

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

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

C. Measures

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

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

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

	or settings that affected the coordination.	or settings that affected the coordination.	or settings that affected the coordination.	affected the coordination.

E. Regional Variances

None.

F. Associated Documents

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

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

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

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

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

Version History

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

G. Reference

Examples of Coordination

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

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or

- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

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

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

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

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

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

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

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

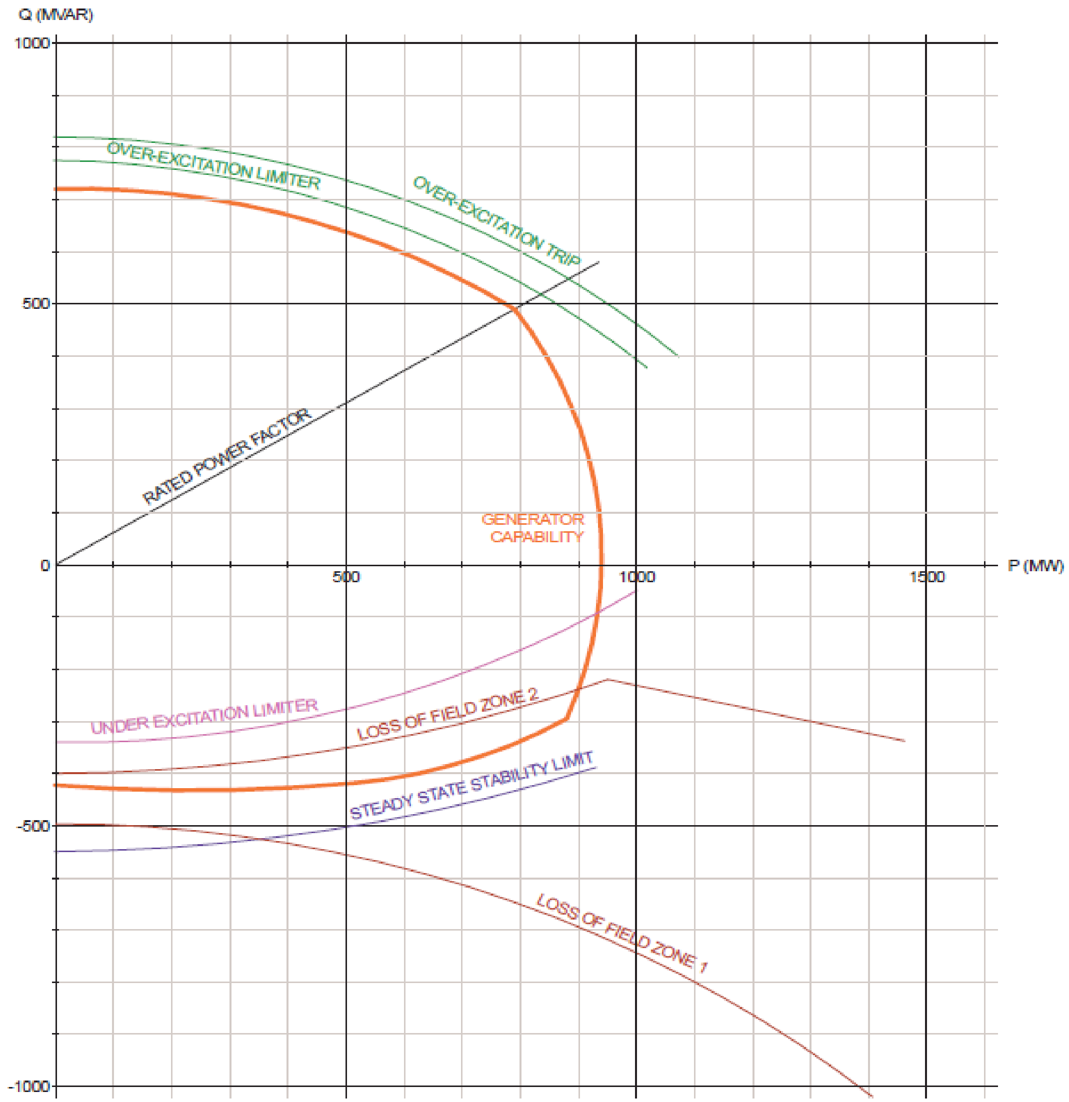
$$R = V^2{}_g/2*(1/X_s+1/X_d)$$

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

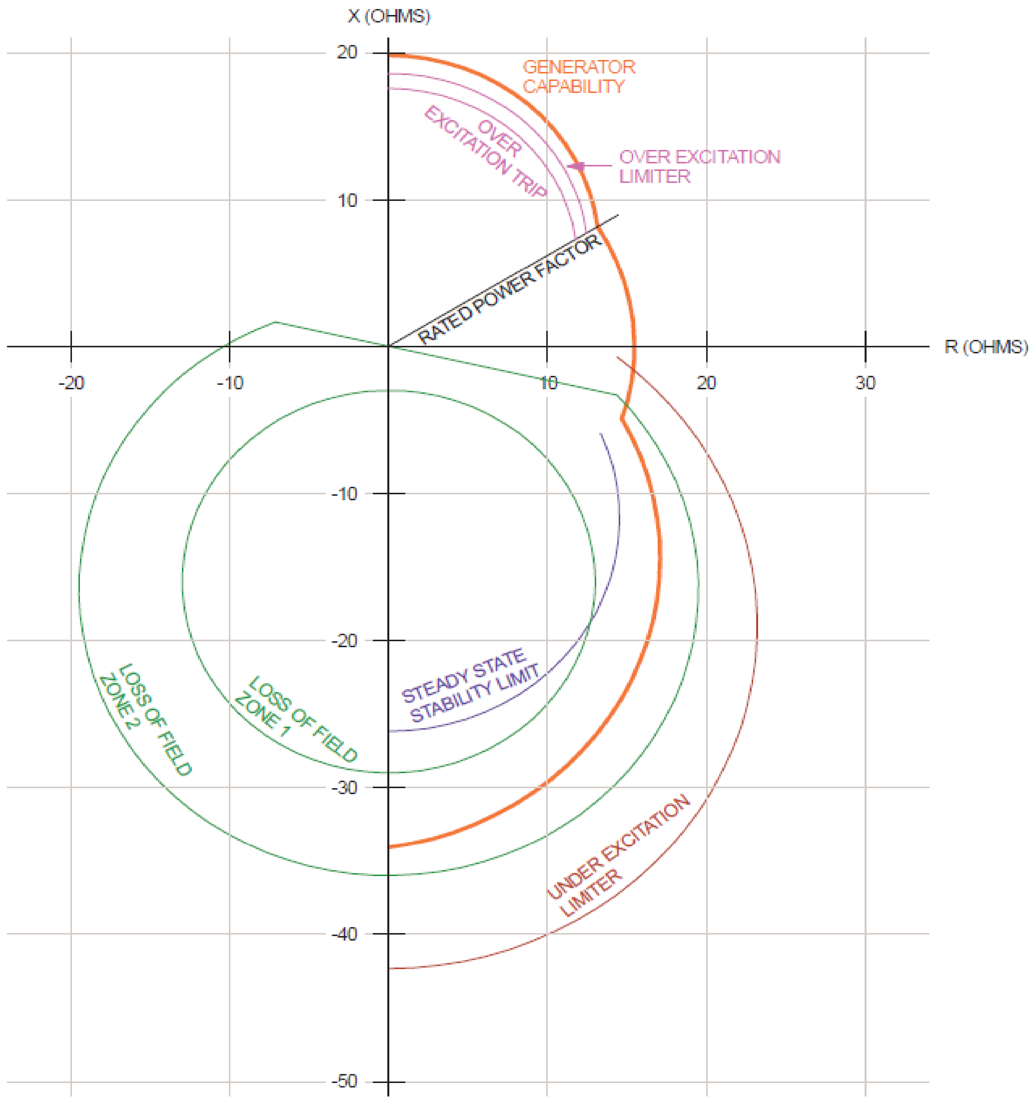
$$C = (X_d - X_s)/2$$

$$R = (X_d + X_s)/2$$

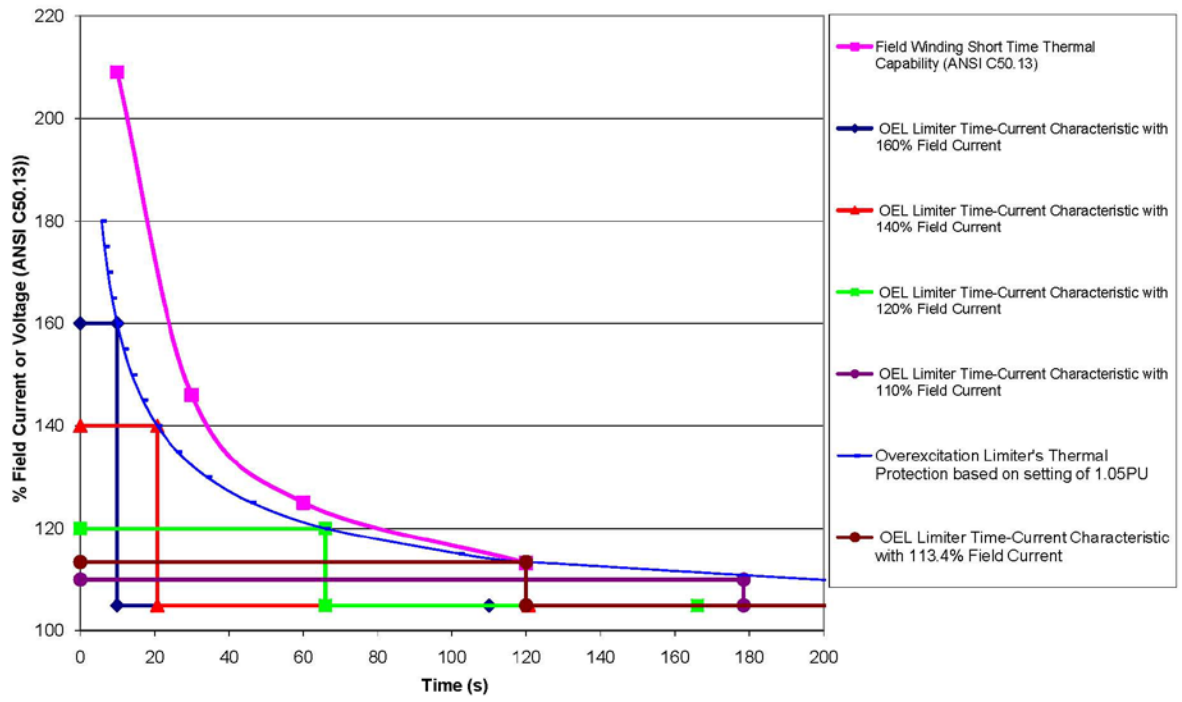
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-024-1(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** **PRC-024-1(X)**
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. Generator Owner
5. **Effective Date:**

   See the Implementation Plan for this standard.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual power producing resources, as well as frequency protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

Rationale for Footnotes 2 and 4

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

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[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

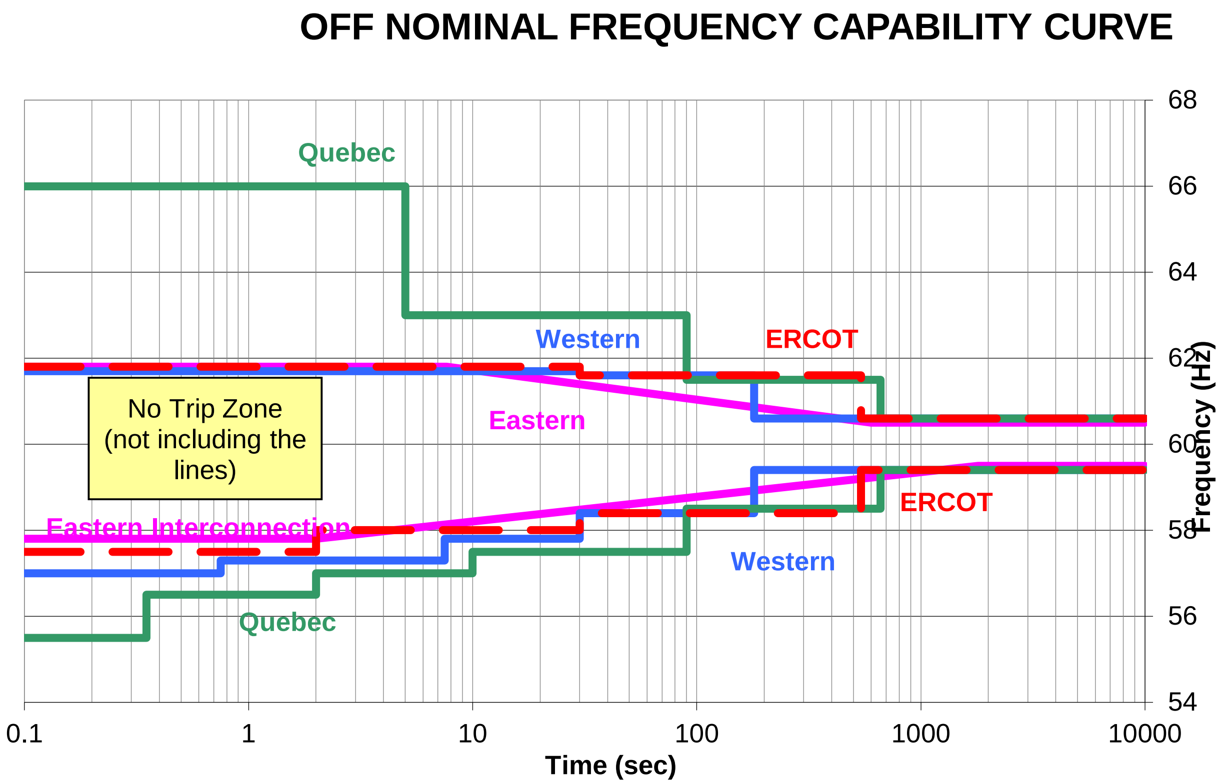
Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

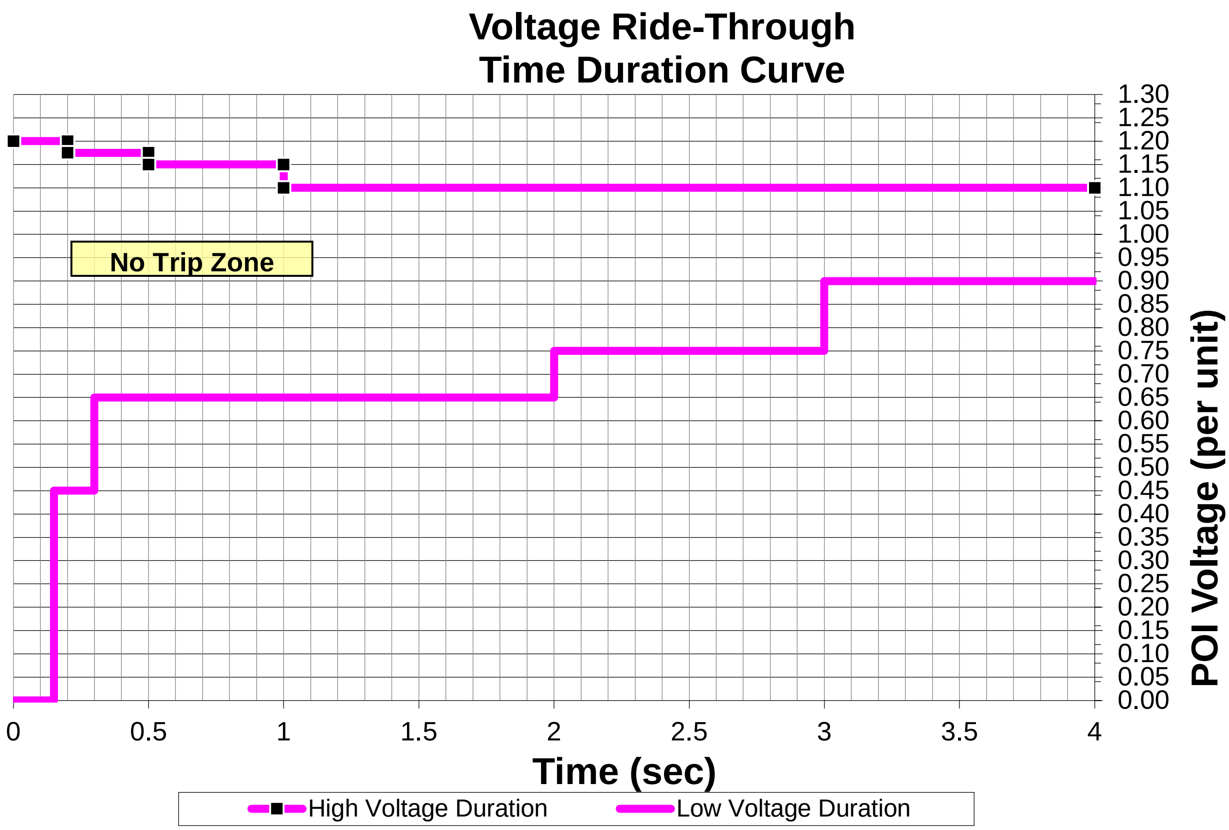
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.

Description of Current Draft

PRC-024-1(X)[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
45-day Additional Formal Comment Period with Additional Ballot (if necessary)	December 2014
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BOT adoption	February 2015

[1] The standard version number currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** **PRC-024-1(X)**
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
   4.1. Generator Owner
5. **Effective Date:**

   See the Implementation Plan for this standard.

~~In those jurisdictions where regulatory approval is required:~~

~~By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~In those jurisdictions where regulatory approval is not required:~~

~~By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Rationale for Footnotes 2 and 4

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set within the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual power producing resources, as well as frequency protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

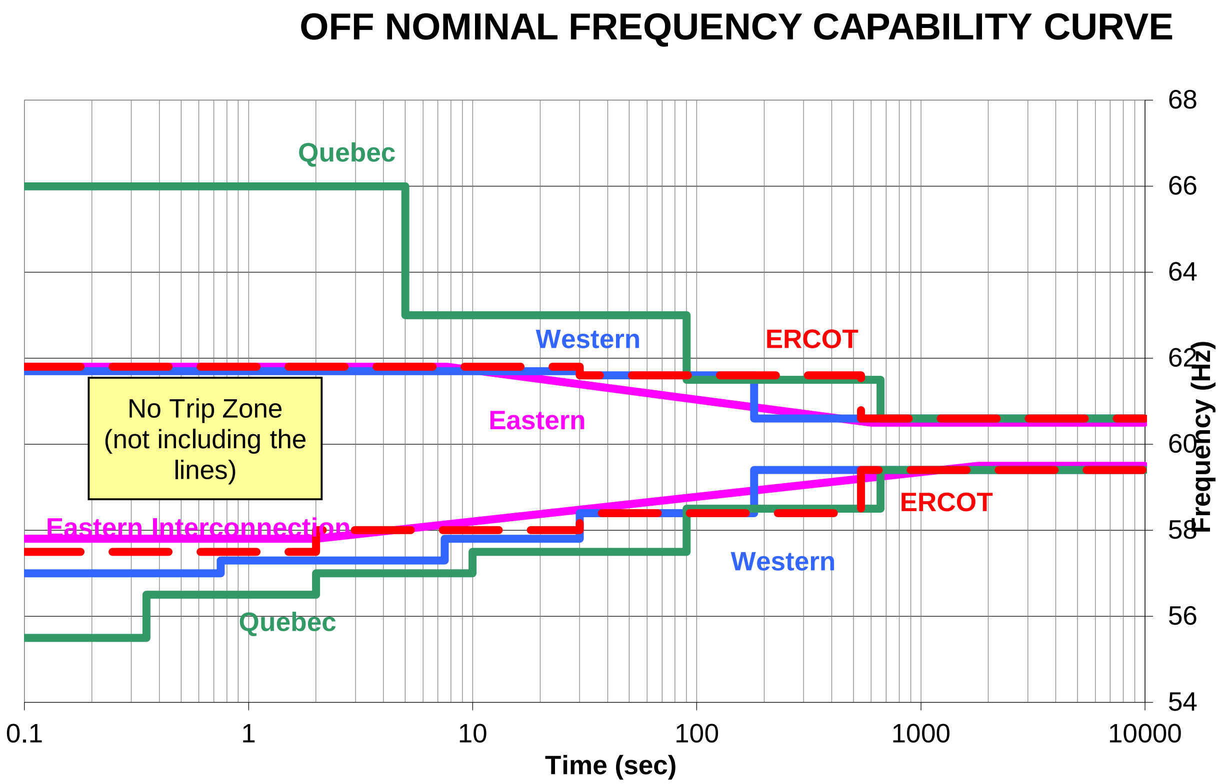
Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

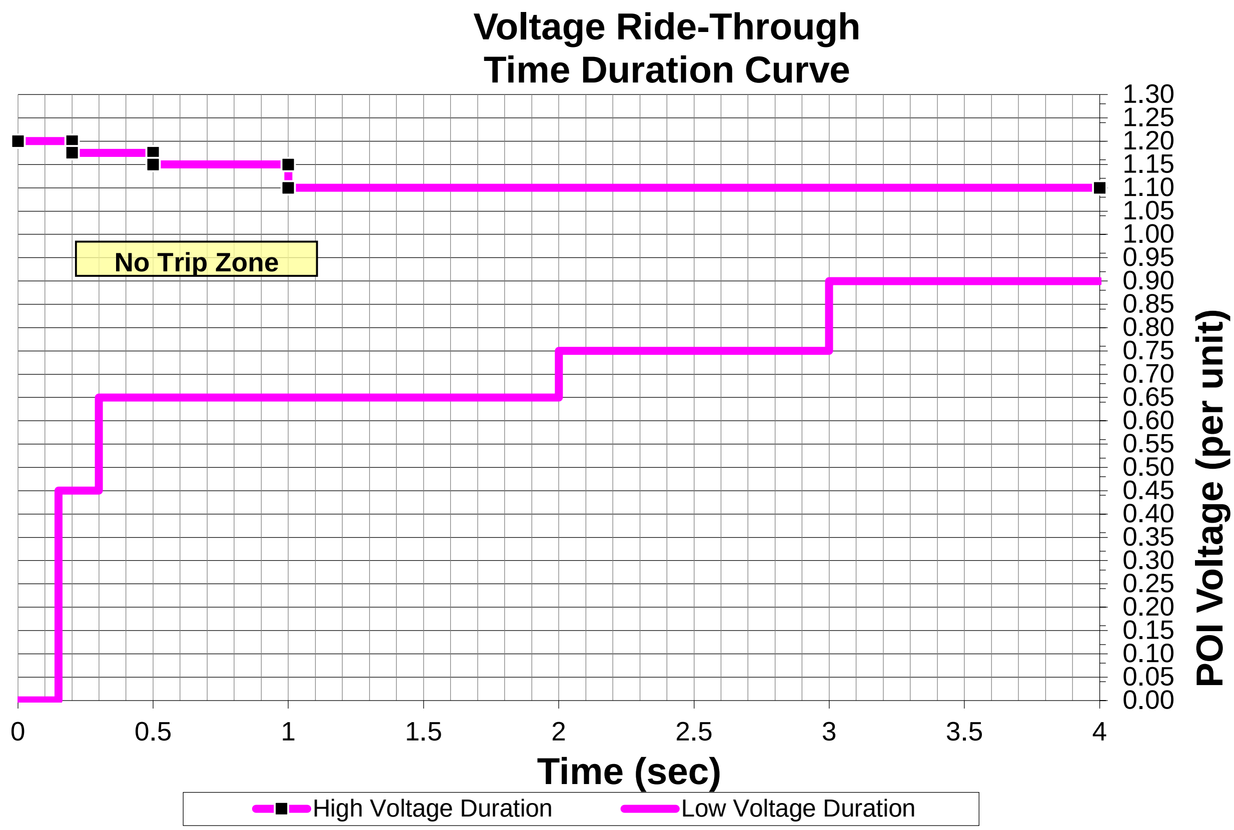
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

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Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(X)

The standard version number currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

Standards Involved
Approval:

- PRC-001-1.1(X) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations
PRC-001-1.1(X) is proposed for approval to align the applicability of PRC-001-1.1a with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources. Given the timing of concurrent standards development of PRC, TRP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.

Effective Date
PRC-001-1.1(X) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

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

Retirement of Existing Standards:

The existing standard, PRC-001-1.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(X).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved
Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations
PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Given the timing of concurrent standards development of PRC projects, PRC-019-1 may already be retired pursuant to an Implementation Plan of a successor version of PRC-. If this occurs, PRC-019-2 will not go into effect.

[1] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

Effective Date
PRC-019-2 shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:
The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2

Applicability:
This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan
All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References
The Implementation Plan for the revised definition of “Bulk Electric System” is available here.

The Implementation Plan for PRC-019-1 is available here.

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Implementation Plan

Dispersed Generation Resources
PRC-024-1(X)

The standard version numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.

Standards Involved
Approval:

- PRC-024-1(X) – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations
PRC-024-1(X) is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.

Effective Date
PRC-024-1(X) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first

calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-1(X).

Applicability:

This standard applies to the following functional entities:

- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-(X) and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of “Bulk Electric System” is available here.

The Implementation Plan for PRC-024-1 is available here.

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Unofficial Comment Form

Project 2014-01 Standards Applicability for Dispersed Generation Resources

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standards. The electronic comment form must be completed by **December 19, 2014**.

If you have questions please contact Katherine Street or by telephone at 404.446.9702.

All documents for this project are available on the project page.

Background Information

This posting solicits formal comments on the three Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) medium-priority Reliability Standards, as identified in the draft White Paper prepared by the Project 2014-01 (Project) standards drafting team (DGR SDT).

The goal of the Project is to ensure that Generator Owners (GOs) and Generator Operators (GOPs) of dispersed power producing resources[1] are appropriately assigned responsibility for requirements that impact the reliability of the Bulk Power System, as the characteristics of operating dispersed power producing resources can be unique. In light of the revised Bulk Electric System (BES) definition approved by the Federal Energy Regulatory Commission in 2014, the intent of this Project is generally to maintain the status quo for applicability of the standards as they have been applied over time with respect to dispersed power producing resources where the status quo does not create a reliability gap.

The DGR SDT reviewed all standards that apply to GOs and GOPs and categorized how each standard should be applied to dispersed power producing resources to accomplish the reliability purpose of the standard. The DGR SDT developed the White Paper to explain its approach, which was posted on April 17, 2014 for an informal comment period.[2] Industry feedback on the White Paper allowed the DGR SDT to refine its approach and finalize recommended revisions to the standards. As part of this review, the DGR SDT determined that there are three medium-priority standards in which attention is required:

- PRC-001-1.1;
- PRC-019-2; and
- PRC-024-1.

Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project, the DGR SDT has developed revisions to allow for different possibilities in the

[1] The terms dispersed generation resources and dispersed power producing resources are used interchangeably.
[2] The current version of the White Paper can be downloaded on the Project web page at http://www.nerc.com/pa/Stand/Pages/Project-2014-01-Standards-Applicability-for-Dispersed-Generation-Resources.aspx.

timing of regulatory approvals. When the revisions are being applied to a version that is not the last approved version of the standard or to a version that is pending regulatory approval, the version is noted with "(X)" after it. Please note that any versions of the standards posted under this project with an "X" suffix will have a version number applied at a later time in order to manage sequencing of version numbers. Please also note that NERC has recently developed a version numbering convention that dictates a different suffix, but since the subject standards were approved by the NERC Standards Committee with the "X" suffix, that convention is maintained here to avoid confusion. The intent of balloting the recommended applicability revisions separately from the technical changes that are ongoing in other projects is to provide flexibility to allow approved applicability revisions to move forward on an expedited timeline as needed to support implementation of the revised definition of the BES.

Summary of Proposed Changes

The DGR SDT's recommended changes are limited to revising the applicability of the relevant versions of PRC-001-1.1, PRC-019-2, and PRC-024-1 to appropriately account for certain dispersed power producing resources.

The DGR SDT has posted the following standards, along with corresponding Implementation Plans:

- PRC-001-1.1(X) (clean and redlined to PRC-001-1.1)
- PRC-019-2 (clean and redlined to PRC-0019-1)
- PRC-024-1(X) (clean and redlined to PRC-024-1)
- SAR

Please note that the DGR SDT has not revised the Violation Risk Factors (VRFs) or Violation Severity Levels (VSLs) associated with the medium-priority standards because the proposed revisions do not change the reliability intent or impact any of the requirements. If the applicability recommendations are approved by industry as proposed, the DGR SDT would not seek to change the VRFs and.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.

   Yes:

   No:

   Comments:

2. Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating control for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.

   Yes:

   No:

   Comments:

3. Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggregating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.

   Yes:

   No:

   Comments:

4. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

   Yes:

   No:

   Comments:

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation		
Date Submitted:	10/1/2013		
SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard. **PRC-005-2** Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply. **FAC-008-3** For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Initial Ballots Now Open through December 22, 2014

Now Available

Initial ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team are open through **8 p.m. Eastern on Monday, December 22, 2014.**

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street,
Standards Developer, or at 404-446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Formal Comment Period Now Open through December 19, 2014

Now Available

A 45-day comment period for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team through **8 p.m. Eastern on Friday, December 19, 2014.**

Instructions for Commenting

Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast ballots. Registered Ballot Body members may join the ballot pools here.

During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool listservs." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool listservs.) The listservs for this project are:

bp-2014-01-PRC-024-1X_in@nerc.com
bp-2014-01-PRC-019-2_in@nerc.com
bp-2014-01_PRC-001-1.1X_in@nerc.com

Next Steps

Initial ballots for the standards will be conducted **December 10-19, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

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bp-2014-01_PRC-001-1.1X_in@nerc.com

Next Steps

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Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Formal Comment Period Now Open through December 19, 2014

Now Available

A 45-day comment period for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team through **8 p.m. Eastern on Friday, December 19, 2014.**

Instructions for Commenting

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During the pre-ballot window, members of the ballot pools may communicate with one another by using their "ballot pool listservs." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool listservs.) The listservs for this project are:

bp-2014-01-PRC-024-1X_in@nerc.com
bp-2014-01-PRC-019-2_in@nerc.com
bp-2014-01_PRC-001-1.1X_in@nerc.com

Next Steps

Initial ballots for the standards will be conducted **December 10-19, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Standards Announcement

Project 2014-01 Applicability for Dispersed Resources Standards
PRC-001-1.1(X), PRC-019-2, and PRC-024-1(X)

Initial Ballot Results

Now Available

Initial ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team concluded at **8 p.m. Eastern, Tuesday, December 23, 2014.**

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Standard	Quorum /Approval
PRC-001-1.1(X)	79.38% / 92.69%
PRC-019-2	79.72% / 93.55%
PRC-024-1(X)	79.60% / 93.67%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards and post them for an additional ballot. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-001-1.1X
Ballot Period:	12/10/2014 - 12/23/2014
Ballot Type:	Initial
Total # Votes:	281
Total Ballot Pool:	354
Quorum:	**79.38 % The Quorum has been reached**
Weighted Segment Vote:	92.69 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	91	1	52	0.929	4	0.071	0	15	20
2 - Segment 2	8	0.5	5	0.5	0	0	0	0	3
3 - Segment 3	82	1	54	0.982	1	0.018	0	14	13
4 - Segment 4	27	1	18	0.947	1	0.053	0	5	3
5 - Segment 5	79	1	45	0.865	7	0.135	0	10	17
6 - Segment 6	52	1	30	0.909	3	0.091	0	7	12
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.3	2	0.2	1	0.1	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	6	0.4	4	0.4	0	0	0	0	2
Totals	**354**	**6.4**	**212**	**5.932**	**17**	**0.468**	**0**	**52**	**73**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES POWER MARKETING)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	SUPPORTS THIRD PARTY COMMENTS - PSEG - (Colorado Springs Utilities)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	

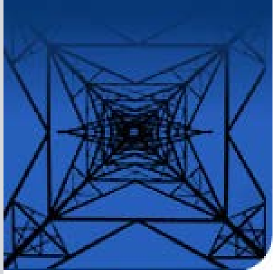
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group (PSEG))
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Abstain	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Wind Energy Transmission Texas, LLC	Julius Horvath		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore		
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	

3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	

3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
				SUPPORTS

5	Colorado Springs Utilities	Kaleb Brimhall	Negative	THIRD PARTY COMMENTS - PSEG - (Colorado Springs Utilities)
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William English)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	

5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - PSEG - (Colorado Springs Utilities)
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		



6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Negative	COMMENT RECEIVED
8		Debra R Warner	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert		

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-019-2
Ballot Period:	12/10/2014 - 12/23/2014
Ballot Type:	Initial
Total # Votes:	283
Total Ballot Pool:	355
Quorum:	**79.72 % The Quorum has been reached**
Weighted Segment Vote:	93.55 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	91	1	51	0.927	4	0.073	0	18	18
2 - Segment 2	7	0.3	2	0.2	1	0.1	0	1	3
3 - Segment 3	83	1	52	0.981	1	0.019	0	16	14
4 - Segment 4	27	1	18	0.947	1	0.053	0	5	3
5 - Segment 5	79	1	48	0.906	5	0.094	0	9	17
6 - Segment 6	52	1	31	0.939	2	0.061	0	7	12
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	7	0.4	4	0.4	0	0	0	1	2
Totals	**355**	**6.2**	**211**	**5.8**	**14**	**0.4**	**0**	**58**	**72**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES POWER MARKETING)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	

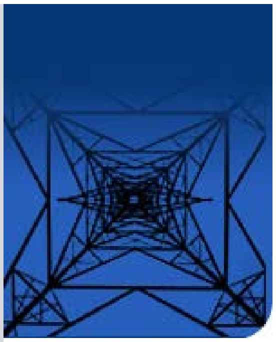
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Abstain	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore		
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	

3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		

5	Dominion Resources Services	Randall C Heise	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion Submitted Comments)
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	

6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Abstain	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	



9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Texas Reliability Entity, Inc.	Derrick Davis	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert		

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-024-1X
Ballot Period:	12/10/2014 - 12/23/2014
Ballot Type:	Initial
Total # Votes:	281
Total Ballot Pool:	353
Quorum:	**79.60 % The Quorum has been reached**
Weighted Segment Vote:	93.67 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	49	0.907	5	0.093	0	18	18
2 - Segment 2	7	0.3	3	0.3	0	0	0	1	3
3 - Segment 3	82	1	50	0.926	4	0.074	0	15	13
4 - Segment 4	27	1	19	0.95	1	0.05	0	4	3
5 - Segment 5	79	1	48	0.906	5	0.094	0	8	18
6 - Segment 6	52	1	31	0.912	3	0.088	0	6	12
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.3	3	0.3	0	0	0	1	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1

10 - Segment 10	6	0.4	4	0.4	0	0	0	0	2
Totals	**353**	**6.3**	**210**	**5.901**	**18**	**0.399**	**0**	**53**	**72**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	SUPPORTS THIRD PARTY COMMENTS - (The individual generating unit of a dispersed power producing resources has negligible impact on BES)
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil		
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	

1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	COMMENT RECEIVED
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung		

3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore		
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer		
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		

3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Power	Marc Donaldson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	

5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (William English)
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion submitted comments)
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	

5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Michael Hill)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barbara Kedrowski)
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion's submitted comments)
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Shivaz Chopra		
6	New York State Electric & Gas Corp.	Julie S King		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	

6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza		
6	Tacoma Public Utilities	Michael C Hill	Negative	COMMENT RECEIVED
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
7	Occidental Chemical	Venona Greaff	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert		

Individual or group. (25 Responses)
Name (13 Responses)
Organization (13 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Question 1 (21 Responses)
Question 1 Comments (21 Responses)
Question 2 (21 Responses)
Question 2 Comments (21 Responses)
Question 3 (21 Responses)
Question 3 Comments (21 Responses)
Question 4 (21 Responses)
Question 4 Comments (21 Responses)

Group
Arizona Public Service Company
Kristie Cocco
Yes
No
The individual generating unit of a dispersed power producing resources has negligible impact on BES performance and should be completely exempt from this requirement in PRC-019,very similar to exemption in PRC-001-1.1(x). Making the standard applicable to individual disperse power producing unit is inappropriate use of the limited resources.
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
No
Although outside of the scope of the work of this Drafting Team, R3.1, as well as all Parts of this standard should be identified as 3.1, etc., and the wording in the added text made consistent with NERC format preferences. Requirement R3.1 should be Part 3.1. Because this is a format change, it should be able to be incorporated in this revision. Also outside the scope of the SAR would be a revision to the Applicability. This standard is not applicable to the Balancing Authority and Host Balancing Authority. Protective system in R3 and Part 3.1 should be replaced with the defined term Protection System. The reference to protective system in the Rationale for Applicability Exclusion in Requirement R3.1 should be revised accordingly.
Yes
Yes
We agree with the revisions proposed in footnotes 4 and 6. However, frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES. However, PRC-001-1.1(X) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6.
Yes
Regarding PRC-024-1(X), the Rationale Box entitled Rationale for Footnotes 2 and 4 should be renamed Rationale for Requirement R1. Footnote 2 does not appear in R1, or on page 4 of the redline. The wording in the Rationale Box entitled Rationale for Footnotes 2 and 4 "…are set within the "no-trip zone" is confusing, as it could easily be interpreted to mean that relays should be set to

trip within the “no-trip zone” which is a contradiction. Suggest rewording to “…are set such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no-trip zone”…”.
Individual
John Falsey
Invenergy LLC
Individual
John Falsey
Invenergy LLC
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
Yes
Yes
No
We are concerned about the evidence required for dispersed power producing resources in measures M1 and M2. Since these devices are expected to be excluded from PRC-005, we will not be required to have calibration or maintenance records for evidence of compliance. We would like measures M1 and M2 of the standard to clearly state that evidence can be original design documents and no periodic testing or verification is required.
No
Individual
David Jendras
Ameren
Individual
Maryclaire Yatsko
Seminole Electric Cooperative, Inc.
Yes
Seminole requests the drafting team to clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, however, that this coordination can take place at the aggregation or interconnection point, instead of at the individual unit.
Yes
Yes
Yes
Individual
David Kiguel
David Kiguel
No
It should be recognized that there might be cases (though rare) where coordination is actually required. Rather than removing applicability of Requirement 3.1 altogether, the standard should require that an assessment of whether coordination is required be performed jointly by the TOP and the GOP. The assessment should address any involved BES elements. If the conclusion of the assessment is that no coordination in required for certain parts of the protections, then and only then, such coordination can be omited.

Yes
Yes
No
Individual
Thomas Foltz
American Electric Power
Yes
The last sentence in the rationale box, "...do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES" might be better stated as "...do not need to be coordinated directly with the transmission protective systems due to the intervening collector system(s)."
Yes
Yes
Yes
The comment form states in part "Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project..." In addition, the redline version of the standard states "Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024." Both these comments infer that at least one other current project impacts PRC-024, but we cannot determine which project(s) that is. Could you provide some clarity on that?
Group
Dominion
Connie Low
Yes
No
Dominion does not believe the addition of 4.2.3.1 is necessary and, in fact introduces ambiguity. Some here read this addition as inferring that, only if the voltage control is applied at the individual resource (as identified in BES I4) would 4.2.3 apply to dispersed power producing resources. If SDT decides to retain, we suggest it be modified to state "This would also include voltage regulating controls that are performed solely at the individual resources dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition."
No
It is Dominions understanding that these footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. Given possible changes to this standard are being actively discussed, Dominion suggests these footnotes not be included until the IEEE standard has implemented a conforming change.
Yes
The language used to describe the Inclusion I4 resources is not consistent. For example: PRC-001 states "individual generating units," PRC-019 states "individual resources," and PRC-024 states "individual generating units and aggregating equipment." Dominion believes the language used in the standard revisions should be consistent with the Inclusion I4 definition. That is: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above
Individual
John Seelke

Public Service Enterprise Group
No
We object to part 3.1 for two reasons: First, individual dispersed resources connected to a collector system will have a protection system and breaker for each generator to isolate them for a fault on the generator-side of that breaker. In the event any individual dispersed resource Protection System or associated breaker fails, the upstream Protection System will need open the main breaker to isolate the fault. The TOP needs to be informed of the upstream protection setting associated with failure an individual generator Protection System or breaker to operate. Second, the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 – System Protection Coordination, and Project 2014-01's SDT should send their concerns to this team so they may address them in their project.
Yes
Yes
No
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
No
In order to provide relief for individual DGRs not being within compliance, the NSRF does recommend that perhaps there could be another set of VSLs established exclusively for DGRs. Case in point, if the entity finds one DGR that is not within the prescribed measures of Attachment 1 or 2, the entity would not be found non-compliant. Our recommendation would be for the Low VSL to >5% of DRGs were not within prescribed settings per Attachment 1 and 2 per of the aggregated Facility. This would allow a very small number of DGRs to have an issue. Or words to that affect. The NSRF believes this recommendation is aligned with the RAI program since one DGR (not within prescribed limits) will not impact the reliability of the BES.
No
Group
Corporate Compliance
Dianne Gordon
Yes
Yes
A possible edit would be to change 4.2.3.1 (regarding individual dispersed gen units) to 4.2.4. This may make the meaning of types of "Applicable Facilities" more clear to the reader.
Yes
Footnotes might be more clear if the language "....(potentially including non-BES equipment)..." were added.
No
Individual
Michael Hill
Tacoma Public Utilties

Yes
Yes
No
The changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment. The purpose of the BES definition is to provide bright line applicability criteria for utilities to better understand which assets are subject to regulatory standards. The revision contained in PRC-024-1(X) deviate from the BES definition. If NERC would like to include Non-BES equipment in the regulatory standards then NERC should modify the BES definition to that end. Should Rationale for Footnotes 2 and 4 be changed to Rationale for Footnotes 4 and 6?
No
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
No
Group
SERC PCS
David Greene
Yes
Yes
If it is the intention of the SDT to exclude individual dispersed power producing resources from the list of Applicable Facilities when voltage regulating control is not performed solely at the individual resources, we suggest that the SDT include the word “only” in R4.2.3.1. “This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition only where voltage regulating control for the facility is performed solely at the individual resources”
Yes
No
The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Michelle R. DAntuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP (ICLP) believes that the project team’s intent in R3.1 is to ensure that only the Protection Systems corresponding to 75+ MVA points of aggregation are applicable, but is not comfortable that the proposed update captures that point. In fact, it seems to only exclude those components protecting individual solar panels/windmills from the requirement to coordinate new

deployments and modifications with the BA and TOP. In our view, the intermediate aggregation points less than 75 MVA are of no practical interest to the BA and TOP – and should be specifically excluded from the requirement. Similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to 75+ MVA aggregation points. Protection System awareness, failures that “reduce system reliability”, and changes in operating conditions that may affect a TOP’s Protection System are only meaningful at those capacity levels. In fact, if too much attention is placed on large numbers of very low-impact systems, there will less consideration made for those that really do present a risk to the BES.
No
ICLP believes that the way that the applicability criteria in PRC-019-2 has been re-framed only includes voltage regulating controls at the single dispersed unit level and at aggregation points at 75 MVA or greater. This omits those voltage controllers serving an entire string of wind mills or solar panels with combined capacity less than 75 MVA. We do not think that was the drafting team’s intent, and suggest that the language be clarified.
Yes
ICLP agrees that it makes sense to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility. We can think of no good technical reason to do otherwise. ICLP is concerned that an overly-enthusiastic CEA could assess a violation if a single relay record is missing among the thousands that would be covered by PRC-024-1(X), but agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm.
No
Group
ACES Standards Collaborators
Jason Marshall
No
While we agree with the concepts and intent to exclude applicability of sub-requirement R3.1 to the individual units of dispersed power producing resources, we do not believe the actual implementation is correct. In an August 10, 2009 informational filing, NERC indicated to the Commission that they would use bulleted lists to indicate when “components may reflect a list of options that may be undertaken to achieve compliance.” Thus, we do not see how a sub-bullet of a sub-requirement can be used to change the applicability of the requirement. We believe the applicability section should be modified to limit applicability of the requirement.
No
We do not oppose applicability of PRC-019 to the individual dispersed power producing resources where voltage regulating control is performed at the individual unit. However, the proposed changes do not accomplish this and actually only serve to confuse the applicability of the standard. All NERC standards are applicable to individual Elements of the BES definition. Since the BES definition includes the individual units of dispersed power producing resource, PRC-019-2 is applicable to those units. Adding sub-section 4.2.3.1 that states this includes “individual dispersed power producing resources… where voltage regulating control for the facility is performed solely at the individual resources” does not add these Elements as they were already included. Furthermore, it does not exclude those individual dispersed power producing resources where voltage regulating control is performed at the aggregate level. The bottom line is that the rationale that is explained in the standard is not accomplished by this change. We believe this standard does not require modification to include “individual dispersed power producing resources… where voltage regulating control for the facility is performed solely at the individual resources” as these resources are already included. However, an explanation in the application guidelines section of the standard is warranted to explain the applicability.
Yes
No
Thank you for the opportunity to comment.

Individual
Larry Heckert
Alliant Energy
Yes
Yes
No
PRC-024-1X requirements R1 and R2 are using the terms “Protective Relaying” and “Protective Relay” with no definition provided for these terms within the NERC glossary of terms or within the standard itself. Footnote 3 is used to define how the term should be applied. The footnote suggests the previously undefined term “Protective Relaying” would be inclusive of any control equipment that contains protective functions. Although the footnote is only represented in standard PRC-024-01(X) and theoretically does not apply to other standards, it could introduce confusion in the other NERC standards that use these terms (e.g., if excitation controls are considered protective relaying under PRC-024, would they be considered as part of a protection system and require utilities to keep excitation control maintenance records under PRC-005?).
No
Group
SPP Standards Review Group
Shannon V. Mickens
Yes
Yes
Yes
Yes
We would suggest to the drafting team in reference to PRC-001-1.1(X) that you would evaluate adding the remaining Measures (M4, M5 and M6) to that particular section. Our concern would be that all the Measures Data pertaining to the Requirements has not been included and this has the potential of causing confusion on what evidence should be provided in an audit. Additionally, we would like the drafting team to provide more clarity on the why there’s a Rationale Box for Footnotes 2 and 4 in reference to PRC-024-1(X). Footnote 2 pertains to interchangeable terms which has been revised to align with the definition of the BES. If the drafting team’s objective is to focus on Footnotes 4 and 6, we would suggest changing the header of the Rationale Box to read “Rationale for Footnotes 4 and 6”. Finally, we would suggest to the drafting team adding Rationale Boxes to all three standards. We feel this would provide clarity to the industry on the expectations of the Requirements in the standards as well as promoting consistency with other documentation associated with this project.
Individual
Venona Greaff
Occidental Chemical Corporation
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes

Yes
No
Individual
Jamison Cawley
Nebraska Public Power District
Yes
Yes
No
In the Rationale for Footnotes 2 and 4, the phrase “including any non-Bulk Electric System collection system equipment” is used. We feel this statement and approach need to be removed because this standard revision hinges on Inclusion I4 of the BES Definition. It is overreaching to add non-BES equipment into a standard. The BES definition serves to identify what facilities are or are not applicable to NERC standards. We feel this adds back to the confusion that was to be avoided with the revised BES Definition.
No
Group
FirstEnergy
Doug Hohlbaugh
Yes
While FirstEnergy (FE) agrees with the exclusion, it should not simply be left to inference that the remainder of the standard does apply to the I4 units at the collector or interconnection point. See FE comments to Question 4 for our suggested approach to add clarity.
Yes
See FE comments to Question 4.
Yes
FE agrees that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, we believe the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2. By adding a section 4.2, it would avoid the need for the footnote approach and make it clearer that the standard is applicable to the dispersed generation equipment by simply evaluating the Applicability Section and having two subsections 4.1 Functional Entities and 4.2 Facilities. See FE comments to Question 4 for additional information.
Yes
FE suggests the standard drafting team give consideration for making consistent use of Section 4 to include both a sub-section 4.1 Functional Entities and 4.2 Facilities. This would alleviate the need to bury pertinent information and clarity around what facilities are in scope within footnotes. Currently only PRC-019 includes both of these applicability sub-sections and they should be used in each standard. The sections may need to be written differently in each of the three standards but should be used in each. Furthermore, standard PRC-019-2 which currently uses sub-section 4.2 Facilities includes text that is simply repeats of what is stated in NERC BES Inclusion statement I2 which could be revised/simplified. As an example, FE believes that section 4 of PRC-019-2 could be written as follows: 4 Applicability 4.1 Functional Entities 4.1.1 Generator Owner 4.1.2 Transmission Owner 4.2 Facilities 4.2.1 Generator Owner – for the purpose of this standard, the term, “applicable Facility” shall mean NERC BES Definition Inclusion I2 and I4. Where voltage regulating control for the BES generation facility is performed solely at the individual resources, those facilities are also included. 4.2.2 Transmission Owner - for the purpose of this standard, the term, “applicable Facility”

shall mean a synchronous condenser that is a qualifying BES facility under NERC BES Definition Inclusion I5. As another example, standard PRC-001-1.1 could be written as follows: 4 Applicability 4.1 Functional Entities 4.1.1 Balancing Authorities 4.1.2 Transmission Operators 4.1.3 Generator Operators 4.2 Facilities 4.2.1 – This standard applies to all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher as clarified by the NERC BES definition Inclusion statements. In regard to Inclusion I4 this standard is not applicable to the individual generating units of dispersed power producing resources. One additional suggestion: Lastly, throughout the various standards there is a footnote indicating "The terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." It appears this footnote is for informational purposes only during the development of standard and will be removed in the final clean version. If that is not the case, consider the need for a NERC Glossary of Term for Dispersed Generation Resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources.
Group
DTE Electric
Kathleen Black
Yes
No
This standard applies at the individual wind turbine level which is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002,where the standards only apply where there is 75 MVA connected at 100kV or higher.
No
Please see our comment for Question 2.
No
No comment.

Additional Comments:

MS Energy
Lance Bean

PRC-001-1.1(X)

- In the new bullet item of R3.1, the standards drafting team refers to individual "generating units". The BES definition Inclusion I4 includes the individual "resources". In PRC-001-1.1(X), would it make sense to replace "generating units" with "resources" to be consistent with the BES definition?

PRC-024-1(X)

- Ahead of the Introduction, there is a statement "the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard". The text box is not in the Applicability section, it is in B. Requirements, R1.
- The text box title is "Rationale for Footnotes 2 and 4". The two new footnotes are 4 and 6. I assume footnotes 1 & 2 will be removed once the Standard is approved, so perhaps the existing title is acceptable.

- The text box refers to individual “generating units”. I think “generating units” should be changed to “resources”.
- The text box also includes the text “it is appropriate to require that protective relay settings…are set within the no-trip zone”. I think the statement should be “it is appropriate to require that protective relay settings…are **not** set within the no-trip zone”

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from November 5, 2014 through December 23, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 98 different people from approximately 69 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standard drafting team's (SDT) response to all industry comments received during this comment period. The DGR SDT encourages commenters to review its responses to ensure all concerns have been addressed. The DGR SDT notes that a significant majority of commenters agree with the DGR SDT's recommendations on the standards, but that several commenters expressed specific concerns. Some comments supporting the DGR SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the DGR SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue. Any comments made on another standard are addressed in the DGR SDT's response to comments on that standard.

1. Summary Consideration

Based on the results from the recent comment and ballot period, it appears that industry overwhelmingly agrees with the DGR SDT's recommendations on applicability changes to PRC-001; PRC-019; and PRC-024, to account for the unique characteristics of dispersed power producing resources[1] in the standards. However, there are some disagreements among stakeholders and suggestions for language revisions contained in industry comments. To the extent that there are comments beyond the scope of this SDT, those comments will be communicated to the appropriate team for consideration.

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

The DGR SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes improve clarity and are consistent with DGR SDT intent and apparent industry consensus. Several commenters suggested non-substantive language changes for standard language as well as explanatory language, such as language in particular rationale boxes. The DGR SDT has carefully considered each comment and has implemented revisions as follows:

- The DGR SDT made non-substantive revisions to the align the terms referring to individual generating units of the dispersed power producing resources in PRC-001; PRC-019; and PRC-024 with one another.

- The DGR SDT revised the language in the Description of Current Draft section of PRC-001; PRC-019; and PRC-024 and PRC-001 the standard, as well as similar language in the standard's Implementation Plan to reflect that there are not any other current projects seeking to revise those standards.

All recommended changes are non-substantive as contemplated by the NERC Standard Processes Manual and therefore do not require an additional ballot. The DGR SDT's consideration of all comments follows.

2. General Comments

At least one commenter recommended that the language describing individual generating units in PRC-001; PRC-019; and PRC-024 should be aligned with one another. The DGR SDT agrees and has therefore made non-substantive revisions to the terms to provide consistency of language among the recommended modifications.

At least one commenter requested that the DGR SDT consider the need for a NERC Glossary term for dispersed generation resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources to address the information contained in the footnote in the standard that indicates "the terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." The DGR SDT expects the use of the terms will be transitional, and that the term used in the NERC BES definition, as included in the Glossary of Terms Used in NERC Reliability Standards, will be the only term used to refer to dispersed generation resources on a going forward basis.

At least one commenter noted that the comment form states in part "because two of the medium-priority standards have recently been revised or are undergoing revision in another current project...," and that additionally, the redline version of the standard states "given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024," but that they were unable to determine another project seeking to revise the standard. The DGR SDT agrees that there are not any other current projects seeking to revise

PRC-024, and has revised the language in the Description of Current Draft section of the standard, as well as similar language in the standard's Implementation Plan.

3. PRC-001

At least one commenter suggested that the applicability sections should be modified to limit applicability of the requirements, rather than using "sub-bullets." The SDT maintains that the approach of utilizing "sub-bullets" to change applicability has been supported by NERC staff during modification of this and other standards, and it is the position of the SDT that the current modification allows specific requirements to be targeted as needed, and that this approach appears to be overwhelmingly supported by the majority of the industry as evidenced by the submitted responses. Therefore, the DGR SDT declines to adopt this suggestion.

One commenter suggested that the standards should require an assessment of whether coordination must be performed jointly by the TOP and the GOP as an alternative to the DGR SDT's suggested changes. Additional coordination is not precluded by the revised standard. Adding a further requirement to jointly assess the necessity of coordination between the TOP, host BA, and the GOP is beyond the scope of the DGR SDT. It is the DGR SDT's position that the proposed revisions to the standard adequately support reliability and are consistent with current practices. Therefore, the SDT declines to adopt this suggestion.

At least one commenter expressed concern that there may be situations where the TOP should be informed of the upstream protection settings associated with failure of an individual generator Protection System or breaker to operate, and also suggested that the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and requested that the DGR SDT communicate their comments to that team so they may address them in their project as they determine appropriate. While the DGR SDT's position will be communicated to the Project 2007-06 SDT, there is a need to address PRC-001 directly as this is still the effective standard. In the proposed modification, the "upstream protection systems," that are at the point of aggregation of 75 MVA or greater are still in scope for dispersed power producing resources, and as such, will be coordinated with the TOP and host BA.

At least one commenter requested the drafting team clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, but that the coordination can take place at the aggregation or interconnection point, rather than at the individual unit level. Also, another commenter expressed concern that R3.1 only excludes individual generator protection equipment from coordinating with the host BA and TOP, and stated that, similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to aggregation points greater than 75 MVA. The DGR SDT maintains that the proposed requirements of the standard adequately support reliability and are consistent with current practices. The proposed modifications to the standard limit the requirements to protective systems associated with the facilities at the point of aggregation of 75 MVA or greater (i.e. substation level protection systems). The applicability for Requirements R1 and R2.1 are explained in the White

Paper. The DGR SDT has determined that the language; "that could require changes in the protection systems of others" adequately limits the scope of requirement R5.1.

One commenter requested that the DGR SDT consider adding Measures to Requirements R4, R5, and R6 of PRC-001; however, addressing Measures for which the DGR SDT did not modify the associated Requirement is beyond the scope of the DGR SDT's SAR.

4. PRC-019

At least one commenter suggested that individual generating units of dispersed power producing resources should be completely exempt from PRC-019's requirements, noting the similarity to the exemption in PRC-001-1.1(ii). Similarly, a commenter stated that applying the standard to the individual wind turbine level is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002. It is the position of the DGR SDT that it is necessary to coordinate voltage regulating controls with the TOP and in the case where voltage control is solely accomplished at the individual unit level, the individual units should be included in the scope of this standard. The DGR SDT has maintained a consistent approach to its recommendations. The DGR SDT maintains that the standard should be applied at the individual unit level, as stated in 4.2.3.1., in order to accomplish the objective of the standard.

At least one commenter expressed concern that the applicability of PRC-019-2 excludes voltage regulating controllers serving a multiplicity of individual generating units with a combined capacity less than 75 MVA. The DGR SDT understands the comment to refer to voltage regulating control at the generating plant/Facility level of BES generators identified through inclusion I4 of the BES definition; however, the revisions to the standard proposed by the DGR SDT expanded the applicability from voltage regulating control at the plant/Facility level, such as voltage controllers serving a multiplicity of individual generating units, to also include individual generating units.

5. PRC-024

At least one commenter suggested that the footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and suggested the footnotes should not be included until the IEEE standard has implemented a conforming change. It is the position of the SDT that addressing IEEE 1547 is beyond the scope of the SDT, as it is not referenced in PRC-024.

At least one commenter suggested the DGR SDT consider including the following sub-sections: 4.1 Functional Entities and 4.2 Facilities rather than using footnotes; however, using a footnote to revise applicability has been supported by NERC staff during modification of this standard. The SDT therefor believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter recommended establishing another set of VSLs established exclusively for DGRs. The DGR SDT agrees that the magnitude of the reliability impact of an individual DGR unit with non-compliant settings should be addressed; however, it is the position of the DGR SDT that this issue is better addressed during the compliance enforcement process. Further, risk assessments performed during RAI should address this issue. The DGR SDT believes the nature of the requirements of Requirements R1 and R2 lend themselves for a pass/fail VSL; therefore, designing a range of severity of non-compliance is inappropriate based on VSL guidelines.

At least one commenter requested that Measures M1 and M2 of the standard clearly state that evidence can be original design documents and no periodic testing or verification is required. The SDT does not see a need to specify what evidence is acceptable strictly for dispersed power producing resources. The SDT believes that the existing use of "evidence" is broad enough to capture the commenter's intent.

At least one commenter stated that the changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment, and indicated that the BES definition should be modified to include non-BES equipment in the regulatory standards rather than particular standards. Similarly, one commenter suggested that the language "including any non-Bulk Electric System collection system equipment" should be omitted from the rationale for footnotes 2 and 4, because the BES definition serves to identify what facilities are or are not applicable to NERC standards.
Reliability standards may apply to specific equipment characteristics, which may include equipment not included through the BES definition. It is not in the DGR SDT's scope of work to modify the definition of BES.

At least one commenter suggested that the language in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing and should be revised. The DGR SDT provided clarifying language.

At least one commenter expressed concern that the use of the terms "Protective Relaying" and "Protective Relay" in Requirements R1 and R2 may introduce confusion in other standards that use the same or similar terms, since, although footnote 3 provides further information about the term, a definition of the terms is not provided in the standard or in the Glossary of Terms Used in NERC Reliability Standards. The terms "protective relaying" and "protective relay" are not capitalized, and are not defined terms as used in Requirements R1 and R2, nor are the terms capitalized or used as defined terms in footnote 3; therefore the use of the terms in this standard have no bearing on the use of the same or similar terms in other standards. The requirement language and footnote 3 address aspects of the standard that were in the previously approved version and not associated with the applicability of dispersed power producing resources, as such revisions to these items are not in the scope of the SDT DGR's SAR to change.

At least one commenter expressed agreement with the revisions proposed in footnotes 4 and 6, but noted that frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES, and expressed concern that PRC-001-1.1(ii) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6. While PRC-001-1.1(ii) excludes coordination of new or changes to existing relays with the TOP and host BA, PRC-024 still requires that these relays be set respecting the "no-trip zone." The SDT does not believe there is a contradiction as the PRC standards address different compliance aspects associated with these relays. Further, PRC-024 Requirement R4 requires the reporting of such relay settings to the TP and PC.

At least one commenter suggested revising the language of the footnotes to add ". . . (potentially including non-BES equipment)..." Thank you for your comment. It is the SDT's position that the language of the footnote as drafted is sufficiently clear and unambiguous.

At least one commenter agreed that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, the commenter expressed that the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2 rather than using a footnote. The approach of utilizing the footnote to revise applicability has been supported by NERC staff members during modification of this standard. The SDT believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter agreed that it is sensible to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility: however, the commenter expressed concern that a violation may be assessed if a single relay record is missing among the potentially thousands of relays that would be covered by PRC-024-2. The commenter went on to note that they agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm. How violations are processed by NERC compliance is not in the purview of the DGR SDT.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

NERC

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Kristie Cocco	Arizona Public Service Company			X		X	X				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Helen Lainis	Independent Electricity Suystem Operator	NPCC	2
11.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Connie Low	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randi Heise	NERC Compliance Policy	NPCC	5
2.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
3.	Larry Nash	Electric Transmission	SERC	
4.	Chip Humphrey	Power Generation Compliance	NPCC	5
5.	Louis Slade	NERC Compliance Policy	RFC	5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 2, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jenson	Western Area Power Administration	MRO	1, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
10.	Marie Knox	Midwest ISO Inc.	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy COmpany	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
5.	Group	Dianne Gordon	Corporate Compliance	X		X		X					

N/A

				1	2	3	4	5	6	7	8	9	10
6.	Group	Sandra Shaffer	PacifiCorp						X				

N/A

				1	2	3	4	5	6	7	8	9	10
7.	Group	David Greene	SERC PCS										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Miller	GTC	SERC	1
2.	Paul Nauert	Ameren	SERC	1, 3
3.	Greg Davis	GTC	SERC	1
4.	James Evans	SCE&G	SERC	1, 3, 5, 6
5.	Steve Edwards	Dominion	SERC	1, 3, 6
6.	George Pitts	TVA	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Paul Jackson	Buckeye Power	RFC	3, 4, 5
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Ginger Mercier	Prairie Power	SERC	3
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Chip Koloini	Golden Spread Electric Cooperative	ERCOT	3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. john falsey	Invenergy LLC	NA - Not Applicable	NA
2. Stephanie Johnson	Westar Energy, Inc.	SPP	1, 3, 5, 6
3. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
4. Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
5. James Nail	City of Independence, Missouri	SPP	3, 5
6. Jonathan Hayes	Southwest Power Pool	SPP	2
7. Robert Rhodes	Southwest Power Pool	SPP	2
8. Shannon Mickens	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Steve Enyeart	Customer Service Engineering	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Bill Smith	FE - RBB - Seg 1	RFC	1
2. Rich Hoag	FE - RBB - Seg 3	RFC	3
3. Doug Hohlbaugh	FE - RBB - Seg 4	RFC	4
4. Ken Dresner	FE - RBB - Seg 5	RFC	5
5. Kevin Querry	FE - RBB - Seg 6	RFC	6
6. Phil Bowers	FE - TO SME	RFC	1
7. Bill Duge	FE - GO SME	RFC	5
8. Rusty Loy	FE - GO SME	RFC	5
9. Steve Wittenauer	FE - TO SME	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Merchant Operations	RFC	5
4. Neil Kennings	Renewable Energy		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5. Barbara Scramlin		DO SOC											
13.	Individual	John Falsey	Invenergy LLC					X					
14.	Individual	John Falsey	Invenergy LLC					X					
15.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
16.	Individual	David Jendras	Ameren	X		X		X	X				
17.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
18.	Individual	David Kiguel	David Kiguel								X		
19.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
20.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
21.	Individual	Michael Hill	Tacoma Public Utilties	X		X	X	X	X				
22.	Individual	Michelle R. DAntuono	Ingleside Cogeneration LP					X					
23.	Individual	Larry Heckert	Alliant Energy				X						
24.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
25.	Individual	Jamison Cawley	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
Invenergy LLC	Agree	Southwest Power Pool
Ameren	Agree	We agree with and adopt the SERC PCS comments for Project 2014-01.
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP

1. **Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.**

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Although outside of the scope of the work of this Drafting Team, R3.1, as well as all Parts of this standard should be identified as 3.1, etc., and the wording in the added text made consistent with NERC format preferences. Requirement R3.1 should be Part 3.1. Because this is a format change, it should be able to be incorporated in this revision. Also outside the scope of the SAR would be a revision to the Applicability. This standard is not applicable to the Balancing Authority and Host Balancing Authority. Protective system in R3 and Part 3.1 should be replaced with the defined term Protection System. The reference to protective system in the Rationale for Applicability Exclusion in Requirement R3.1 should be revised accordingly.
ACES Standards Collaborators	No	While we agree with the concepts and intent to exclude applicability of sub-requirement R3.1 to the individual units of dispersed power producing resources, we do not believe the actual implementation is correct. In an August 10, 2009 informational filing, NERC indicated to the Commission that they would use bulleted lists to indicate when "components may reflect a list of options that may be undertaken to achieve compliance." Thus, we do not see how a sub-bullet of a sub-requirement can be used to change the applicability of the requirement. We believe the applicability section should be modified to limit applicability of the requirement.
David Kiguel	No	It should be recognized that there might be cases (though rare) where coordination is actually required. Rather than removing applicability of Requirement 3.1 altogether, the standard should require that an assessment of whether coordination is required be performed jointly by the

Organization	Yes or No	Question 1 Comment
		TOP and the GOP. The assessment should address any involved BES elements. If the conclusion of the assessment is that no coordination in required for certain parts of the protections, then and only then, such coordination can be omited.
Public Service Enterprise Group	No	We object to part 3.1 for two reasons: First, individual dispersed resources connected to a collector system will have a protection system and breaker for each generator to isolate them for a fault on the generator-side of that breaker. In the event any individual dispersed resource Protection System or associated breaker fails, the upstream Protection System will need open the main breaker to isolate the fault. The TOP needs to be informed of the upstream protection setting associated with failure an individual generator Protection System or breaker to operate. Second, the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and Project 2014-01's SDT should send their concerns to this team so they may address them in their project.
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP (ICLP) believes that the project team's intent in R3.1 is to ensure that only the Protection Systems corresponding to 75+ MVA points of aggregation are applicable, but is not comfortable that the proposed update captures that point. In fact, it seems to only exclude those components protecting individual solar panels/windmills from the requirement to coordinate new deployments and modifications with the BA and TOP. In our view, the intermediate aggregation points less than 75 MVA are of no practical interest to the BA and TOP - and should be specifically excluded from the requirement. Similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to 75+ MVA aggregation points. Protection System awareness, failures that "reduce system reliability", and changes in operating conditions that may affect a TOP's Protection System are only meaningful at those capacity levels. In fact, if too much attention is placed on large numbers of very low-impact systems,

Organization	Yes or No	Question 1 Comment
		there will less consideration made for those that really do present a risk to the BES.
Arizona Public Service Company	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	
Corporate Compliance	Yes	
PacifiCorp	Yes	
SERC PCS	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	While FirstEnergy (FE) agrees with the exclusion, it should not simply be left to inference that the remainder of the standard does apply to the I4 units at the collector or interconnection point. See FE comments to Question 4 for our suggested approach to add clarity.
DTE Electric	Yes	
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	Seminole requests the drafting team to clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES

Organization	Yes or No	Question 1 Comment
		definition, however, that this coordination can take place at the aggregation or interconnection point, instead of at the individual unit.
American Electric Power	Yes	The last sentence in the rationale box, "...do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES" might be better stated as "...do not need to be coordinated directly with the transmission protective systems due to the intervening collector system(s)."
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	
Nebraska Public Power District	Yes	
Invenergy LLC		

2. Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating control for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	The individual generating unit of a dispersed power producing resources has negligible impact on BES performance and should be completely exempt from this requirement in PRC-019, very similar to exemption in PRC-001-1.1(x). Making the standard applicable to individual disperse power producing unit is inappropriate use of the limited resources.
Dominion	No	Dominion does not believe the addition of 4.2.3.1 is necessary and, in fact introduces ambiguity. Some here read this addition as inferring that, only if the voltage control is applied at the individual resource (as identified in BES I4) would 4.2.3 apply to dispersed power producing resources. If SDT decides to retain, we suggest it be modified to state "This would also include voltage regulating controls that are performed solely at the individual resources dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition."
ACES Standards Collaborators	No	We do not oppose applicability of PRC-019 to the individual dispersed power producing resources where voltage regulating control is performed at the individual unit. However, the proposed changes do not accomplish this and actually only serve to confuse the applicability of the standard. All NERC standards are applicable to individual Elements of the BES definition. Since the BES definition includes the individual units of dispersed power producing resource, PRC-019-2 is applicable to those units. Adding sub-section 4.2.3.1 that states this includes "individual dispersed power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" does not add these Elements as they were already included. Furthermore, it does not exclude those individual dispersed power producing resources where voltage regulating control is performed at the aggregate level. The bottom line is that the rationale that is explained in the

Organization	Yes or No	Question 2 Comment
		standard is not accomplished by this change. We believe this standard does not require modification to include “individual dispersed power producing resources... where voltage regulating control for the facility is performed solely at the individual resources” as these resources are already included. However, an explanation in the application guidelines section of the standard is warranted to explain the applicability.
DTE Electric	No	This standard applies at the individual wind turbine level which is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002, where the standards only apply where there is 75 MVA connected at 100kV or higher.
Ingleside Cogeneration LP	No	ICLP believes that the way that the applicability criteria in PRC-019-2 has been re-framed only includes voltage regulating controls at the single dispersed unit level and at aggregation points at 75 MVA or greater. This omits those voltage controllers serving an entire string of wind mills or solar panels with combined capacity less than 75 MVA. We do not think that was the drafting team’s intent, and suggest that the language be clarified.
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	
Corporate Compliance	Yes	A possible edit would be to change 4.2.3.1 (regarding individual dispersed gen units) to 4.2.4. This may make the meaning of types of "Applicable Facilities" more clear to the reader.
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
SERC PCS	Yes	If it is the intention of the SDT to exclude individual dispersed power producing resources from the list of Applicable Facilities when voltage regulating control is not performed solely at the individual resources, we suggest that the SDT include the word "only" in R4.2.3.1. "This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition only where voltage regulating control for the facility is performed solely at the individual resources"
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	See FE comments to Question 4.
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	Yes	

3. **Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggregating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.**

Organization	Yes or No	Question 3 Comment
Dominion	No	It is Dominions understanding that these footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. Given possible changes to this standard are being actively discussed, Dominion suggests these footnotes not be included until the IEEE standard has implemented a conforming change.
MRO NERC Standards Review Forum	No	In order to provide relief for individual DGRs not being within compliance, the NSRF does recommend that perhaps there could be another set of VSLs established exclusively for DGRs. Case in point, if the entity finds one DGR that is not within the prescribed measures of Attachment 1 or 2, the entity would not be found non-compliant. Our recommendation would be for the Low VSL to >5% of DRGs were not within prescribed settings per Attachment 1 and 2 per of the aggregated Facility. This would allow a very small number of DGRs to have an issue. Or words to that affect. The NSRF believes this recommendation is aligned with the RAI program since one DGR (not within prescribed limits) will not impact the reliability of the BES.
DTE Electric	No	Please see our comment for Question 2.
Wisconsin Electric Power Company	No	We are concerned about the evidence required for dispersed power producing resources in measures M1 and M2. Since these devices are expected to be excluded from PRC-005, we will not be required to have calibration or maintenance records for evidence of compliance. We would like measures M1 and M2 of the standard to clearly state that evidence can be original design documents and no periodic testing or verification is required.

Organization	Yes or No	Question 3 Comment
Tacoma Public Utilties	No	The changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment. The purpose of the BES definition is to provide bright line applicability criteria for utilities to better understand which assets are subject to regulatory standards. The revision contained in PRC-024-1(X) deviate from the BES definition. If NERC would like to include Non-BES equipment in the regulatory standards then NERC should modify the BES definition to that end. Should Rationale for Footnotes 2 and 4 be changed to Rationale for Footnotes 4 and 6?
Alliant Energy	No	PRC-024-1X requirements R1 and R2 are using the terms “Protective Relaying” and “Protective Relay” with no definition provided for these terms within the NERC glossary of terms or within the standard itself. Footnote 3 is used to define how the term should be applied. The footnote suggests the previously undefined term “Protective Relaying” would be inclusive of any control equipment that contains protective functions. Although the footnote is only represented in standard PRC-024-01(X) and theoretically does not apply to other standards, it could introduce confusion in the other NERC standards that use these terms (e.g., if excitation controls are considered protective relaying under PRC-024, would they be considered as part of a protection system and require utilities to keep excitation control maintenance records under PRC-005?).
Nebraska Public Power District	No	In the Rationale for Footnotes 2 and 4, the phrase “including any non-Bulk Electric System collection system equipment” is used. We feel this statement and approach need to be removed because this standard revision hinges on Inclusion I4 of the BES Definition. It is overreaching to add non-BES equipment into a standard. The BES definition serves to identify what facilities are or are not applicable to NERC standards. We feel this adds back to the confusion that was to be avoided with the revised BES Definition.
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	We agree with the revisions proposed in footnotes 4 and 6. However, frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES. However, PRC-001-1.1(X) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6.
Corporate Compliance	Yes	Footnotes might be more clear if the language "....(potentially including non-BES equipment)..." were added.
PacifiCorp	Yes	
SERC PCS	Yes	
ACES Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	FE agrees that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, we believe the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2. By adding a section 4.2, it would avoid the need for the footnote approach and make it clearer that the standard is applicable to the dispersed generation equipment by simply evaluating the Applicability Section and having two subsections 4.1 Functional Entities and 4.2 Facilities. See FE comments to Question 4 for additional information.

Organization	Yes or No	Question 3 Comment
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Ingleside Cogeneration LP	Yes	ICLP agrees that it makes sense to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility. We can think of no good technical reason to do otherwise. ICLP is concerned that an overly-enthusiastic CEA could assess a violation if a single relay record is missing among the thousands that would be covered by PRC-024-1(X), but agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm.

4. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
MRO NERC Standards Review Forum	No	
Corporate Compliance	No	
PacifiCorp	No	
SERC PCS	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
ACES Standards Collaborators	No	Thank you for the opportunity to comment.
Bonneville Power Administration	No	
DTE Electric	No	No comment.
Wisconsin Electric Power Company	No	
David Kiguel	No	
Public Service Enterprise Group	No	

Organization	Yes or No	Question 4 Comment
Tacoma Public Utilties	No	
Ingleside Cogeneration LP	No	
Alliant Energy	No	
Nebraska Public Power District	No	
Northeast Power Coordinating Council	Yes	Regarding PRC-024-1(X), the Rationale Box entitled Rationale for Footnotes 2 and 4 should be renamed Rationale for Requirement R1. Footnote 2 does not appear in R1, or on page 4 of the redline. The wording in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing, as it could easily be interpreted to mean that relays should be set to trip within the "no-trip zone" which is a contradiction. Suggest rewording to "...are set such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no-trip zone"...".
Dominion	Yes	The language used to describe the Inclusion I4 resources is not consistent. For example:PRC-001 states "individual generating units," PRC-019 states "individual resources," and PRC-024 states "individual generating units and aggregating equipment." Dominion believes the language used in the standard revisions should be consistent with the Inclusion I4 definition. That is: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above
SPP Standards Review Group	Yes	We would suggest to the drafting team in reference to PRC-001-1.1(X) that you would evaluate adding the remaining Measures (M4, M5 and M6) to that particular section. Our concern would be that all the Measures Data pertaining to the Requirements has not been included and this has the potential of causing confusion on what evidence should be provided in an audit. Additionally, we would like the drafting team to

Organization	Yes or No	Question 4 Comment
		provide more clarity on the why there's a Rationale Box for Footnotes 2 and 4 in reference to PRC-024-1(X). Footnote 2 pertains to interchangeable terms which has been revised to align with the definition of the BES. If the drafting team's objective is to focus on Footnotes 4 and 6, we would suggest changing the header of the Rationale Box to read "Rationale for Footnotes 4 and 6". Finally, we would suggest to the drafting team adding Rationale Boxes to all three standards. We feel this would provide clarity to the industry on the expectations of the Requirements in the standards as well as promoting consistency with other documentation associated with this project.
FirstEnergy	Yes	FE suggests the standard drafting team give consideration for making consistent use of Section 4 to include both a sub-section 4.1 Functional Entities and 4.2 Facilities. This would alleviate the need to bury pertinent information and clarity around what facilities are in scope within footnotes. Currently only PRC-019 includes both of these applicability sub-sections and they should be used in each standard. The sections may need to be written differently in each of the three standards but should be used in each. Furthermore, standard PRC-019-2 which currently uses sub-section 4.2 Facilities includes text that is simply repeats of what is stated in NERC BES Inclusion statement I2 which could be revised/simplified. As an example, FE believes that section 4 of PRC-019-2 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Generator Owner 4.1.2 Transmission Owner 4.2 Facilities 4.2.1 Generator Owner - for the purpose of this standard, the term, "applicable Facility" shall mean NERC BES Definition Inclusion I2 and I4. Where voltage regulating control for the BES generation facility is performed solely at the individual resources, those facilities are also included. 4.2.2 Transmission Owner - for the purpose of this standard, the term, "applicable Facility" shall mean a synchronous condenser that is a qualifying BES facility under NERC BES Definition Inclusion I5.As another example, standard PRC-001-1.1 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Balancing Authorities 4.1.2 Transmission Operators 4.1.3 Generator Operators 4.2 Facilities 4.2.1 - This standard applies to all Transmission Elements operated at 100 kV or higher and Real Power and Reactive

Organization	Yes or No	Question 4 Comment
		Power resources connected at 100 kV or higher as clarified by the NERC BES definition Inclusion statements. In regard to Inclusion I4 this standard is not applicable to the individual generating units of dispersed power producing resources. One additional suggestion: Lastly, throughout the various standards there is a footnote indicating "The terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." It appears this footnote is for informational purposes only during the development of standard and will be removed in the final clean version. If that is not the case, consider the need for a NERC Glossary of Term for Dispersed Generation Resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources.
Seminole Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	The comment form states in part "Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project..." In addition, the redline version of the standard states "Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024." Both these comments infer that at least one other current project impacts PRC-024, but we cannot determine which project(s) that is. Could you provide some clarity on that?

Additional Comments:
MS Energy
Lance Bean

<u>PRC-001-1.1(X)</u>

- In the new bullet item of R3.1, the standards drafting team refers to individual “generating units”. The BES definition Inclusion I4 includes the individual “resources”. In PRC-001-1.1(X), would it make sense to replace “generating units” with “resources” to be consistent with the BES definition?

PRC-024-1(X)

- Ahead of the Introduction, there is a statement “the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard”. The text box is not in the Applicability section, it is in B. Requirements, R1.
- The text box title is “Rationale for Footnotes 2 and 4”. The two new footnotes are 4 and 6. I assume footnotes 1 & 2 will be removed once the Standard is approved, so perhaps the existing title is acceptable.
- The text box refers to individual “generating units”. I think “generating units” should be changed to “resources”.
- The text box also includes the text “it is appropriate to require that protective relay settings…are set within the no-trip zone”. I think the statement should be “it is appropriate to require that protective relay settings…are **not** set within the no-trip zone”

END OF REPORT

Consideration of Comments

Project 2014-01 Standards Applicability for Dispersed Generation Resources

The Project 2014-01 Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from November 5, 2014 through December 23, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 98 different people from approximately 69 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

This document contains the Project 2014-01 Standards Applicability for Dispersed Generation Resources (DGR) standard drafting team's (SDT) response to all industry comments received during this comment period. The DGR SDT encourages commenters to review its responses to ensure all concerns have been addressed. The DGR SDT notes that a significant majority of commenters agree with the DGR SDT's recommendations on the standards, but that several commenters expressed specific concerns. Some comments supporting the DGR SDT's recommendations are discussed below but in most cases are not specifically addressed in this response. Also, several comments in response to specific questions are duplicated in other questions, and several commenters raise substantively the same concerns as others. Therefore, the DGR SDT's consideration of all comments is addressed in this section in summary form, with duplicate comments treated as a single issue. Any comments made on another standard are addressed in the DGR SDT's response to comments on that standard.

1. Summary Consideration

Based on the results from the recent comment and ballot period, it appears that industry overwhelmingly agrees with the DGR SDT's recommendations on applicability changes to PRC-001; PRC-019; and PRC-024, to account for the unique characteristics of dispersed power producing resources[1] in the standards. However, there are some disagreements among stakeholders and suggestions for language revisions contained in industry comments. To the extent that there are comments beyond the scope of this SDT, those comments will be communicated to the appropriate team for consideration.

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

The DGR SDT has carefully reviewed and considered each stakeholder comment and has revised its recommendations where suggested changes improve clarity and are consistent with DGR SDT intent and apparent industry consensus. Several commenters suggested non-substantive language changes for standard language as well as explanatory language, such as language in particular rationale boxes. The DGR SDT has carefully considered each comment and has implemented revisions as ~~appropriate~~follows:

- The DGR SDT made non-substantive revisions to the align the terms referring to individual generating units of the dispersed power producing resources in PRC-001; PRC-019; and PRC-024 with one another.
- The DGR SDT revised the language in the Description of Current Draft section of PRC-001; PRC-019; and PRC-024 and PRC-001 the standard, as well as similar language in the standard's Implementation Plan to reflect that there are not any other current projects seeking to revise those standards.

~~. However, A~~All recommended changes are non-substantive as contemplated by the NERC Standard Processes Manual and therefore do not require an additional ballot. The DGR SDT's consideration of all comments follows.

2. General Comments

At least one commenter recommended that the language describing individual generating units in PRC-001; PRC-019; and PRC-024 should be aligned with one another. The DGR SDT agrees and has therefore made non-substantive revisions to the terms to provide consistency of language among the recommended modifications.

At least one commenter requested that the DGR SDT consider the need for a NERC Glossary term for dispersed generation resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources to address the information contained in the footnote in the standard that indicates "the terms 'dispersed generation resources' and 'dispersed power producing resources' are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES." The DGR SDT expects the use of the terms will be transitional, and that the term used in the NERC BES definition, as included in the Glossary of Terms Used in NERC Reliability Standards, will be the only term used to refer to dispersed generation resources on a going forward basis.

At least one commenter noted that the comment form states in part "because two of the medium-priority standards have recently been revised or are undergoing revision in another current project...," and that additionally, the redline version of the standard states "given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024," but that they were unable to determine another project seeking to revise the standard. The DGR SDT agrees that there are not any other current projects seeking to revise PRC-024, and has revised the language in the Description of Current Draft section of the standard, as well as similar language in the standard's Implementation Plan.

NERC

3. PRC-001

At least one commenter suggested that the applicability sections should be modified to limit applicability of the requirements, rather than using "sub-bullets." The SDT maintains that the approach of utilizing "sub-bullets" to change applicability has been supported by NERC staff during modification of this and other standards, and it is the position of the SDT that the current modification allows specific requirements to be targeted as needed, and that this approach appears to be overwhelmingly supported by the majority of the industry as evidenced by the submitted responses. Therefore, the DGR SDT declines to adopt this suggestion.

One commenter suggested that the standards should require an assessment of whether coordination must be performed jointly by the TOP and the GOP as an alternative to the DGR SDT's suggested changes. Additional coordination is not precluded by the revised standard. Adding a further requirement to jointly assess the necessity of coordination between the TOP, host BA, and the GOP is beyond the scope of the DGR SDT. It is the DGR SDT's position that the proposed revisions to the standard adequately support reliability and are consistent with current practices. Therefore, the SDT declines to adopt this suggestion.

At least one commenter expressed concern that there may be situations where the TOP should be informed of the upstream protection settings associated with failure of an individual generator Protection System or breaker to operate, and also suggested that the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and requested that the DGR SDT communicate their comments to that team so they may address them in their project as they determine appropriate. While the DGR SDT's position will be communicated to the Project 2007-06 SDT, there is a need to address PRC-001 directly as this is still the effective standard. In the proposed modification, the "upstream protection systems," that are at the point of aggregation of 75 MVA or greater are still in scope for dispersed power producing resources, and as such, will be coordinated with the TOP and host BA.

At least one commenter requested the drafting team clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, but that the coordination can take place at the aggregation or interconnection point, rather than at the individual unit level. Also, another commenter expressed concern that R3.1 only excludes individual generator protection equipment from coordinating with the host BA and TOP, and stated that, similarly, the applicability of Requirements R1, R2.1, and R5.1 should be limited to aggregation points greater than 75 MVA. The DGR SDT maintains that the proposed requirements of the standard adequately support reliability and are consistent with current practices. The proposed modifications to the standard limit the requirements to protective systems associated with the facilities at the point of aggregation of 75 MVA or greater (i.e. substation level protection systems). The applicability for Requirements R1 and R2.1 are explained in the White Paper. The DGR SDT has determined that the language; "that could require changes in the protection systems of others" adequately limits the scope of requirement R5.1.

One commenter requested that the DGR SDT consider adding Measures to Requirements R4, R5, and R6 of PRC-001; however, addressing Measures for which the DGR SDT did not modify the associated Requirement is beyond the scope of the DGR SDT's SAR.

4. PRC-019

At least one commenter suggested that individual generating units of dispersed power producing resources should be completely exempt from PRC-019's requirements, noting the similarity to the exemption in PRC-001-1.1(~~x~~ii). Similarly, a commenter stated that applying the standard to the individual wind turbine level is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002. It is the position of the DGR SDT that it is necessary to coordinate voltage regulating controls with the TOP and in the case where voltage control is solely accomplished at the individual unit level, the individual units should be included in the scope of this standard. The DGR SDT has maintained a consistent approach to its recommendations. The DGR SDT maintains that the standard should be applied at the individual unit level, as stated in 4.2.3.1., in order to accomplish the objective of the standard.

At least one commenter expressed concern that the applicability of PRC-019-2 excludes voltage regulating controllers serving a multiplicity of individual generating units with a combined capacity less than 75 MVA. The DGR SDT understands the comment to refer to voltage regulating control at the generating plant/Facility level of BES generators identified through inclusion I4 of the BES definition; however, the revisions to the standard proposed by the DGR SDT expanded the applicability from voltage regulating control at the plant/Facility level, such as voltage controllers serving a multiplicity of individual generating units, to also include individual generating units.

5. PRC-024

At least one commenter suggested that the footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems and suggested the footnotes should not be included until the IEEE standard has implemented a conforming change. It is the position of the SDT that addressing IEEE 1547 is beyond the scope of the SDT, as it is not referenced in PRC-024.

At least one commenter suggested the DGR SDT consider including the following sub-sections: 4.1 Functional Entities and 4.2 Facilities rather than using footnotes; however, using a footnote to revise applicability has been supported by NERC staff during modification of this standard. The SDT therefor believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter recommended establishing another set of VSLs established exclusively for DGRs. The DGR SDT agrees that the magnitude of the reliability impact of an individual DGR unit with non-compliant settings should be addressed; however, it is the position of the DGR SDT that this issue is better addressed during the compliance enforcement process. Further, risk assessments performed during RAI should address this issue. The DGR SDT believes the nature of the requirements of Requirements R1 and R2 lend themselves for a pass/fail VSL; therefore, designing a range of severity of non-compliance is inappropriate based on VSL guidelines.

At least one commenter requested that Measures M1 and M2 of the standard clearly state that evidence can be original design documents and no periodic testing or verification is required. The SDT does not see a need to specify what evidence is acceptable strictly for dispersed power producing resources. The SDT believes that the existing use of “evidence” is broad enough to capture the commenter’s intent.

At least one commenter stated that the changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment, and indicated that the BES definition should be modified to include non-BES equipment in the regulatory standards rather than particular standards. Similarly, one commenter suggested that the language “including any non-Bulk Electric System collection system equipment” should be omitted from the rationale for footnotes 2 and 4, because the BES definition serves to identify what facilities are or are not applicable to NERC standards.
Reliability standards may apply to specific equipment characteristics, which may include equipment not included through the BES definition. It is not in the DGR SDT’s scope of work to modify the definition of BES.

At least one commenter suggested that the language in the Rationale Box entitled Rationale for Footnotes 2 and 4 “...are set within the “no-trip zone” is confusing and should be revised. The DGR SDT provided clarifying language.

At least one commenter expressed concern that the use of the terms “Protective Relaying” and “Protective Relay” in Requirements R1 and R2 may introduce confusion in other standards that use the same or similar terms, since, although footnote 3 provides further information about the term, a definition of the terms is not provided in the standard or in the Glossary of Terms Used in NERC Reliability Standards. The terms “protective relaying” and “protective relay” are not capitalized, and are not defined terms as used in Requirements R1 and R2, nor are the terms capitalized or used as defined terms in footnote 3; therefore the use of the terms in this standard have no bearing on the use of the same or similar terms in other standards. The requirement language and footnote 3 address aspects of the standard that were in the previously approved version and not associated with the applicability of dispersed power producing resources, as such revisions to these items are not in the scope of the SDT DGR’s SAR to change.

At least one commenter expressed agreement with the revisions proposed in footnotes 4 and 6, but noted that frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES, and expressed concern that PRC-001-1.1(~~X~~ii) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6. While PRC-001-1.1(~~x~~ii) excludes coordination of new or changes to existing relays with the TOP and host BA, PRC-024 still requires that these relays be set respecting the "no-trip zone." The SDT does not believe there is a contradiction as the PRC standards address different compliance aspects associated with these relays. Further, PRC-024 Requirement R4 requires the reporting of such relay settings to the TP and PC.

At least one commenter suggested revising the language of the footnotes to add ". . . (potentially including non-BES equipment)..." Thank you for your comment. It is the SDT's position that the language of the footnote as drafted is sufficiently clear and unambiguous.

At least one commenter agreed that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, the commenter expressed that the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2 rather than using a footnote. The approach of utilizing the footnote to revise applicability has been supported by NERC staff members during modification of this standard. The SDT believes the proposed modification is satisfactory and thus declines to incorporate the suggested modification.

At least one commenter agreed that it is sensible to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility: however, the commenter expressed concern that a violation may be assessed if a single relay record is missing among the potentially thousands of relays that would be covered by PRC-024-2~~1(X)~~. The commenter went on to note that they agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm. How violations are processed by NERC compliance is not in the purview of the DGR SDT.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Kristie Cocco	Arizona Public Service Company			X		X	X				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Helen Lainis	Independent Electricity Suystem Operator	NPCC	2
11.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Connie Low	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randi Heise	NERC Compliance Policy	NPCC	5
2.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
3.	Larry Nash	Electric Transmission	SERC	
4.	Chip Humphrey	Power Generation Compliance	NPCC	5
5.	Louis Slade	NERC Compliance Policy	RFC	5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative, Inc.	MRO	1, 2, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jenson	Western Area Power Administration	MRO	1, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
10.	Marie Knox	Midwest ISO Inc.	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy COmpany	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Dianne Gordon	Corporate Compliance	X		X		X					

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Sandra Shaffer	PacifiCorp						X				

N/A

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	David Greene	SERC PCS										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Miller	GTC	SERC	1
2.	Paul Nauert	Ameren	SERC	1, 3
3.	Greg Davis	GTC	SERC	1
4.	James Evans	SCE&G	SERC	1, 3, 5, 6
5.	Steve Edwards	Dominion	SERC	1, 3, 6
6.	George Pitts	TVA	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Solomon	Hoosier Energy	RFC	1
2.	Paul Jackson	Buckeye Power	RFC	3, 4, 5
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
4.	Ginger Mercier	Prairie Power	SERC	3
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Chip Koloini	Golden Spread Electric Cooperative	ERCOT	3, 5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	john falsey	Invenergy LLC	NA - Not Applicable	NA
2.	Stephanie Johnson	Westar Energy, Inc.	SPP	1, 3, 5, 6
3.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
4.	Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
5.	James Nail	City of Independence, Missouri	SPP	3, 5
6.	Jonathan Hayes	Southwest Power Pool	SPP	2
7.	Robert Rhodes	Southwest Power Pool	SPP	2
8.	Shannon Mickens	Southwest Power Pool	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Enyeart	Customer Service Engineering	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	FE - RBB - Seg 1	RFC	1
2.	Rich Hoag	FE - RBB - Seg 3	RFC	3
3.	Doug Hohlbaugh	FE - RBB - Seg 4	RFC	4
4.	Ken Dresner	FE - RBB - Seg 5	RFC	5
5.	Kevin Querry	FE - RBB - Seg 6	RFC	6
6.	Phil Bowers	FE - TO SME	RFC	1
7.	Bill Duge	FE - GO SME	RFC	5
8.	Rusty Loy	FE - GO SME	RFC	5
9.	Steve Wittenauer	FE - TO SME	RFC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5
4.	Neil Kennings	Renewable Energy		

No.	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
	5. Barbara Scramlin	DO SOC											
13.	Individual	John Falsey	Invenergy LLC					X					
14.	Individual	John Falsey	Invenergy LLC					X					
15.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
16.	Individual	David Jendras	Ameren	X		X		X	X				
17.	Individual	Maryclaire Yatsko	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
18.	Individual	David Kiguel	David Kiguel								X		
19.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
20.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
21.	Individual	Michael Hill	Tacoma Public Utilties	X		X	X	X	X				
22.	Individual	Michelle R. DAntuono	Ingleside Cogeneration LP					X					
23.	Individual	Larry Heckert	Alliant Energy				X						
24.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
25.	Individual	Jamison Cawley	Nebraska Public Power District	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

~~**Summary Consideration:**~~

Organization	Agree	Supporting Comments of "Entity Name"
Invenergy LLC	Agree	Southwest Power Pool
Ameren	Agree	We agree with and adopt the SERC PCS comments for Project 2014-01.
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP

1. **Do you agree with the revisions proposed in PRC-001-1.1(X) Requirement R3 part 3.1 to exclude the individual generating units of dispersed power producing resources identified through Inclusion I4 of the BES definition from this requirement? If not, please provide technical rationale for your disagreement, along with suggested language changes.**

~~**Summary Consideration:**~~

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Although outside of the scope of the work of this Drafting Team, R3.1, as well as all Parts of this standard should be identified as 3.1, etc., and the wording in the added text made consistent with NERC format preferences. Requirement R3.1 should be Part 3.1. Because this is a format change, it should be able to be incorporated in this revision. Also outside the scope of the SAR would be a revision to the Applicability. This standard is not applicable to the Balancing Authority and Host Balancing Authority. Protective system in R3 and Part 3.1 should be replaced with the defined term Protection System. The reference to protective system in the Rationale for Applicability Exclusion in Requirement R3.1 should be revised accordingly.
ACES Standards Collaborators	No	While we agree with the concepts and intent to exclude applicability of sub-requirement R3.1 to the individual units of dispersed power producing resources, we do not believe the actual implementation is correct. In an August 10, 2009 informational filing, NERC indicated to the Commission that they would use bulleted lists to indicate when “components may reflect a list of options that may be undertaken to achieve compliance.” Thus, we do not see how a sub-bullet of a sub-requirement can be used to change the applicability of the requirement. We believe the applicability section should be modified to limit applicability of the requirement.

Organization	Yes or No	Question 1 Comment
David Kiguel	No	It should be recognized that there might be cases (though rare) where coordination is actually required. Rather than removing applicability of Requirement 3.1 altogether, the standard should require that an assessment of whether coordination is required be performed jointly by the TOP and the GOP. The assessment should address any involved BES elements. If the conclusion of the assessment is that no coordination in required for certain parts of the protections, then and only then, such coordination can be omited.
Public Service Enterprise Group	No	We object to part 3.1 for two reasons: First, individual dispersed resources connected to a collector system will have a protection system and breaker for each generator to isolate them for a fault on the generator-side of that breaker. In the event any individual dispersed resource Protection System or associated breaker fails, the upstream Protection System will need open the main breaker to isolate the fault. The TOP needs to be informed of the upstream protection setting associated with failure an individual generator Protection System or breaker to operate. Second, the coordination of Protections Systems between GOs and TOs is the subject of Project 2007-06 - System Protection Coordination, and Project 2014-01's SDT should send their concerns to this team so they may address them in their project.
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP (ICLP) believes that the project team's intent in R3.1 is to ensure that only the Protection Systems corresponding to 75+ MVA points of aggregation are applicable, but is not comfortable that the proposed update captures that point. In fact, it seems to only exclude those components protecting individual solar panels/windmills from the requirement to coordinate new deployments and modifications with the BA and TOP. In our view, the intermediate aggregation points less than 75 MVA are of no practical interest to the BA and TOP - and should be specifically excluded from the requirement. Similarly, the applicability of

Organization	Yes or No	Question 1 Comment
		Requirements R1, R2.1, and R5.1 should be limited to 75+ MVA aggregation points. Protection System awareness, failures that “reduce system reliability”, and changes in operating conditions that may affect a TOP’s Protection System are only meaningful at those capacity levels. In fact, if too much attention is placed on large numbers of very low-impact systems, there will less consideration made for those that really do present a risk to the BES.
Arizona Public Service Company	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	
Corporate Compliance	Yes	
PacifiCorp	Yes	
SERC PCS	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	While FirstEnergy (FE) agrees with the exclusion, it should not simply be left to inference that the remainder of the standard does apply to the I4 units at the collector or interconnection point. See FE comments to Question 4 for our suggested approach to add clarity.
DTE Electric	Yes	

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	Seminole requests the drafting team to clarify that R3.1 still requires system protection coordination for generating units covered by I4 of the BES definition, however, that this coordination can take place at the aggregation or interconnection point, instead of at the individual unit.
American Electric Power	Yes	The last sentence in the rationale box, "...do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES" might be better stated as "...do not need to be coordinated directly with the transmission protective systems due to the intervening collector system(s)."
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	
Nebraska Public Power District	Yes	
Invenergy LLC		

2. Do you agree with the revisions proposed in the Facilities section of proposed PRC-019-2 to clarify that the standard is applicable to dispersed power producing resources identified through Inclusion I4 of the BES definition where voltage regulating control for the facility is performed solely at the individual resource? If not, please provide technical rationale for your disagreement, along with suggested language changes.

~~**Summary Consideration:**~~

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	The individual generating unit of a dispersed power producing resources has negligible impact on BES performance and should be completely exempt from this requirement in PRC-019, very similar to exemption in PRC-001-1.1(x). Making the standard applicable to individual disperse power producing unit ~~-~~ is inappropriate use of the limited resources.
Dominion	No	Dominion does not believe the addition of 4.2.3.1 is necessary and, in fact introduces ambiguity. Some here read this addition as inferring that, only if the voltage control is applied at the individual resource (as identified in BES I4) would 4.2.3 apply to dispersed power producing resources. If SDT decides to retain, we suggest it be modified to state "This would also include voltage regulating controls that are performed solely at the individual resources dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition."
ACES Standards Collaborators	No	We do not oppose applicability of PRC-019 to the individual dispersed power producing resources where voltage regulating control is performed at the individual unit. However, the proposed changes do not accomplish this and actually only serve to confuse the applicability of the standard. All NERC standards are applicable to individual Elements of the BES definition. Since the BES definition includes the individual units of dispersed power producing resource, PRC-019-2 is applicable to those units. Adding sub-section 4.2.3.1 that states this includes "individual dispersed

Organization	Yes or No	Question 2 Comment
		power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" does not add these Elements as they were already included. Furthermore, it does not exclude those individual dispersed power producing resources where voltage regulating control is performed at the aggregate level. The bottom line is that the rationale that is explained in the standard is not accomplished by this change. We believe this standard does not require modification to include "individual dispersed power producing resources... where voltage regulating control for the facility is performed solely at the individual resources" as these resources are already included. However, an explanation in the application guidelines section of the standard is warranted to explain the applicability.
DTE Electric	No	This standard applies at the individual wind turbine level which is inconsistent with the revisions to PRC-001, PRC-004 and VAR-002, where the standards only apply where there is 75 MVA connected at 100kV or higher.
Ingleside Cogeneration LP	No	ICLP believes that the way that the applicability criteria in PRC-019-2 has been re-framed only includes voltage regulating controls at the single dispersed unit level and at aggregation points at 75 MVA or greater. This omits those voltage controllers serving an entire string of wind mills or solar panels with combined capacity less than 75 MVA. We do not think that was the drafting team's intent, and suggest that the language be clarified.
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	

Organization	Yes or No	Question 2 Comment
Corporate Compliance	Yes	A possible edit would be to change 4.2.3.1 (regarding individual dispersed gen units) to 4.2.4. This may make the meaning of types of "Applicable Facilities" more clear to the reader.
PacifiCorp	Yes	
SERC PCS	Yes	If it is the intention of the SDT to exclude individual dispersed power producing resources from the list of Applicable Facilities when voltage regulating control is not performed solely at the individual resources, we suggest that the SDT include the word “only” in R4.2.3.1. “This includes individual dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition only where voltage regulating control for the facility is performed solely at the individual resources”
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	See FE comments to Question 4.
Wisconsin Electric Power Company	Yes	
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group	Yes	
Tacoma Public Utilties	Yes	
Alliant Energy	Yes	
Nebraska Public Power District	Yes	

3. Do you agree with the revisions proposed in PRC-024-1(X) to clarify (via footnotes 4 and 6) that Requirements R1 and R2 are applicable to both dispersed power producing resources identified through Inclusion I4 of the BES definition, as well as any aggregating equipment (potentially including non-BES equipment) from the individual resource up to the point of interconnection? If not, please provide technical rationale for your disagreement, along with suggested language changes.

~~**Summary Consideration:**~~

Organization	Yes or No	Question 3 Comment
Dominion	No	It is Dominions understanding that these footnotes conflict with the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. Given possible changes to this standard are being actively discussed, Dominion suggests these footnotes not be included until the IEEE standard has implemented a conforming change.
MRO NERC Standards Review Forum	No	In order to provide relief for individual DGRs not being within compliance, the NSRF does recommend that perhaps there could be another set of VSLs established exclusively for DGRs. Case in point, if the entity finds one DGR that is not within the prescribed measures of Attachment 1 or 2, the entity would not be found non-compliant. Our recommendation would be for the Low VSL to >5% of DRGs were not within prescribed settings per Attachment 1 and 2 per of the aggregated Facility. This would allow a very small number of DGRs to have an issue. Or words to that affect. The NSRF believes this recommendation is aligned with the RAI program since one DGR (not within prescribed limits) will not impact the reliability of the BES.
DTE Electric	No	Please see our comment for Question 2.
Wisconsin Electric Power Company	No	We are concerned about the evidence required for dispersed power producing resources in measures M1 and M2. Since these devices are expected to be excluded from PRC-005, we will not be required to have calibration or maintenance records for

Organization	Yes or No	Question 3 Comment
		evidence of compliance. We would like measures M1 and M2 of the standard to clearly state that evidence can be original design documents and no periodic testing or verification is required.
Tacoma Public Utilties	No	The changes to PRC-024-1(X) include the applicability of the standard to Bulk Power System equipment that is not BES equipment. The purpose of the BES definition is to provide bright line applicability criteria for utilities to better understand which assets are subject to regulatory standards. The revision contained in PRC-024-1(X) deviate from the BES definition. If NERC would like to include Non-BES equipment in the regulatory standards then NERC should modify the BES definition to that end. Should Rationale for Footnotes 2 and 4 be changed to Rationale for Footnotes 4 and 6?
Alliant Energy	No	PRC-024-1X requirements R1 and R2 are using the terms “Protective Relaying” and “Protective Relay” with no definition provided for these terms within the NERC glossary of terms or within the standard itself. Footnote 3 is used to define how the term should be applied. The footnote suggests the previously undefined term “Protective Relaying” would be inclusive of any control equipment that contains protective functions. Although the footnote is only represented in standard PRC-024-01(X) and theoretically does not apply to other standards, it could introduce confusion in the other NERC standards that use these terms (e.g., if excitation controls are considered protective relaying under PRC-024, would they be considered as part of a protection system and require utilities to keep excitation control maintenance records under PRC-005?).
Nebraska Public Power District	No	In the Rationale for Footnotes 2 and 4, the phrase “including any non-Bulk Electric System collection system equipment” is used. We feel this statement and approach need to be removed because this standard revision hinges on Inclusion I4 of the BES Definition. It is overreaching to add non-BES equipment into a standard. The BES definition serves to identify what facilities are or are not applicable to NERC

Organization	Yes or No	Question 3 Comment
		standards. We feel this adds back to the confusion that was to be avoided with the revised BES Definition.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	We agree with the revisions proposed in footnotes 4 and 6. However, frequency and voltage protective relays require coordination with other protective relays implemented elsewhere on the BES. However, PRC-001-1.1(X) Part 3.1 is excluding coordination of protective relays for Inclusion I4 which contradicts footnotes 4 and 6.
Corporate Compliance	Yes	Footnotes might be more clear if the language "....(potentially including non-BES equipment)..." were added.
PacifiCorp	Yes	
SERC PCS	Yes	
ACES Standards Collaborators	Yes	
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	FE agrees that the PRC-024-1 standard in regard to NERC BES facilities I4 should apply to the voltage protective relays applied on the individual power producing resources, as well as voltage protective relays applied on equipment from the individual power producing resource up to the point of interconnection. However, we believe the SDT should make use of a Facilities Applicability section 4.2 as is done in many NERC standards such as PRC-019-2. By adding a section 4.2, it would avoid the need for the

Organization	Yes or No	Question 3 Comment
		footnote approach and make it clearer that the standard is applicable to the dispersed generation equipment by simply evaluating the Applicability Section and having two subsections 4.1 Functional Entities and 4.2 Facilities. See FE comments to Question 4 for additional information.
Seminole Electric Cooperative, Inc.	Yes	
David Kiguel	Yes	
American Electric Power	Yes	
Public Service Enterprise Group	Yes	
Ingleside Cogeneration LP	Yes	ICLP agrees that it makes sense to set the voltage and frequency ride-through settings consistently throughout a dispersed generation facility. We can think of no good technical reason to do otherwise. ICLP is concerned that an overly-enthusiastic CEA could assess a violation if a single relay record is missing among the thousands that would be covered by PRC-024-1(X), but agree that the RAI initiative has established an environment where a more reasonable compliance approach will be the norm.

4. Do you have any additional comments to assist the DGR SDT in further developing its recommendations?

~~**Summary Consideration:**~~

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
MRO NERC Standards Review Forum	No	
Corporate Compliance	No	
PacifiCorp	No	
SERC PCS	No	The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
ACES Standards Collaborators	No	Thank you for the opportunity to comment.
Bonneville Power Administration	No	
DTE Electric	No	No comment.
Wisconsin Electric Power Company	No	

Organization	Yes or No	Question 4 Comment
David Kiguel	No	
Public Service Enterprise Group	No	
Tacoma Public Utilties	No	
Ingleside Cogeneration LP	No	
Alliant Energy	No	
Nebraska Public Power District	No	
Northeast Power Coordinating Council	Yes	Regarding PRC-024-1(X), the Rationale Box entitled Rationale for Footnotes 2 and 4 should be renamed Rationale for Requirement R1. Footnote 2 does not appear in R1, or on page 4 of the redline. The wording in the Rationale Box entitled Rationale for Footnotes 2 and 4 "...are set within the "no-trip zone" is confusing, as it could easily be interpreted to mean that relays should be set to trip within the "no-trip zone" which is a contradiction. Suggest rewording to "...are set such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no-trip zone"...".
Dominion	Yes	The language used to describe the Inclusion I4 resources is not consistent. For example:PRC-001 states "individual generating units," PRC-019 states "individual resources," and PRC-024 states "individual generating units and aggregating equipment." Dominion believes the language used in the standard revisions should be consistent with the Inclusion I4 definition. That is: a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above

Organization	Yes or No	Question 4 Comment
SPP Standards Review Group	Yes	We would suggest to the drafting team in reference to PRC-001-1.1(X) that you would evaluate adding the remaining Measures (M4, M5 and M6) to that particular section. Our concern would be that all the Measures Data pertaining to the Requirements has not been included and this has the potential of causing confusion on what evidence should be provided in an audit. Additionally, we would like the drafting team to provide more clarity on the why there's a Rationale Box for Footnotes 2 and 4 in reference to PRC-024-1(X). Footnote 2 pertains to interchangeable terms which has been revised to align with the definition of the BES. If the drafting team's objective is to focus on Footnotes 4 and 6, we would suggest changing the header of the Rationale Box to read "Rationale for Footnotes 4 and 6". Finally, we would suggest to the drafting team adding Rationale Boxes to all three standards. We feel this would provide clarity to the industry on the expectations of the Requirements in the standards as well as promoting consistency with other documentation associated with this project.
FirstEnergy	Yes	FE suggests the standard drafting team give consideration for making consistent use of Section 4 to include both a sub-section 4.1 Functional Entities and 4.2 Facilities. This would alleviate the need to bury pertinent information and clarity around what facilities are in scope within footnotes. Currently only PRC-019 includes both of these applicability sub-sections and they should be used in each standard. The sections may need to be written differently in each of the three standards but should be used in each. Furthermore, standard PRC-019-2 which currently uses sub-section 4.2 Facilities includes text that is simply repeats of what is stated in NERC BES Inclusion statement I2 which could be revised/simplified. As an example, FE believes that section 4 of PRC-019-2 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Generator Owner 4.1.2 Transmission Owner 4.2 Facilities 4.2.1 Generator Owner - for the purpose of this standard, the term, "applicable Facility" shall mean NERC BES Definition Inclusion I2 and I4. Where voltage regulating control for the BES generation facility is performed solely at the individual resources, those facilities are also included. 4.2.2 Transmission Owner - for the purpose of this

Organization	Yes or No	Question 4 Comment
		standard, the term, “applicable Facility” shall mean a synchronous condenser that is a qualifying BES facility under NERC BES Definition Inclusion I5.As another example, standard PRC-001-1.1 could be written as follows:4 Applicability 4.1 Functional Entities 4.1.1 Balancing Authorities 4.1.2 Transmission Operators 4.1.3 Generator Operators 4.2 Facilities 4.2.1 - This standard applies to all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher as clarified by the NERC BES definition Inclusion statements. In regard to Inclusion I4 this standard is not applicable to the individual generating units of dispersed power producing resources. One additional suggestion: Lastly, throughout the various standards there is a footnote indicating “The terms ‘dispersed generation resources’ and ‘dispersed power producing resources’ are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.” It appears this footnote is for informational purposes only during the development of standard and will be removed in the final clean version. If that is not the case, consider the need for a NERC Glossary of Term for Dispersed Generation Resource that would indicate it is synonymous with the NERC BES Definition in regard to Inclusion statement I4 for dispersed power producing resources.
Seminole Electric Cooperative, Inc.	Yes	
American Electric Power	Yes	The comment form states in part “Because two of the medium-priority standards have recently been revised or are undergoing revision in another current project...” In addition, the redline version of the standard states “Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024.” Both these comments infer that at least one other current project impacts PRC-024, but we cannot determine which project(s) that is. Could you provide some clarity on that?

Additional Comments:
MS Energy
Lance Bean

<u>PRC-001-1.1(X)</u>

- In the new bullet item of R3.1, the standards drafting team refers to individual “generating units”. The BES definition Inclusion I4 includes the individual “resources”. In PRC-001-1.1(X), would it make sense to replace “generating units” with “resources” to be consistent with the BES definition?

<u>PRC-024-1(X)</u>

- Ahead of the Introduction, there is a statement “the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard”. The text box is not in the Applicability section, it is in B. Requirements, R1.
- The text box title is “Rationale for Footnotes 2 and 4”. The two new footnotes are 4 and 6. I assume footnotes 1 & 2 will be removed once the Standard is approved, so perhaps the existing title is acceptable.
- The text box refers to individual “generating units”. I think “generating units” should be changed to “resources”.
- The text box also includes the text “it is appropriate to require that protective relay settings…are set within the no-trip zone”. I think the statement should be “it is appropriate to require that protective relay settings…are **not** set within the no-trip zone”

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.

Description of Current Draft

PRC-001-1.1(ii)[1] is proposed for approval to align the applicability of PRC-001-1.1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot. ,

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

A. Introduction

1. Title: **System Protection Coordination**

2. Number: PRC-001-1.1(ii)

3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. Effective Date:

See the Implementation Plan for PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

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

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

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

> Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

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

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

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

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

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

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

1.3. Data Retention

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

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

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

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

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

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii))	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. ~~2.~~3. Initial posting of revised standard PRC-001-1.1(ii) on November 5, 2014.

Description of Current Draft

PRC-001-1.1(~~X~~ii)[1] is proposed for approval to align the applicability of PRC-001-1.1~~a~~ with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team (SDT) has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.[2] ~~Given the timing of concurrent standards development of PRC, TOP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~December 2014~~
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.~~currently includes an (X) to indicate the version numbering will be updated. Some standards are open in current projects, and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **System Protection Coordination**
2. **Number:** PRC-001-1.1(~~X~~ii)
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.
4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators
5. **Effective Date:**

   See the Implementation Plan for ~~this standard~~PRC-001-1.1(ii).

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

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

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

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

- Requirement R3.1 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

Rationale for the Applicability Exclusion in Requirement R3.1

Coordination of new or changes to protective systems associated with dispersed power producing resources identified through Inclusion I4 of the BES definition are typically performed on the interconnecting facilities. New or changes to protective systems associated with these facilities should be coordinated with the TOP as these protective systems typically must be closely coordinated with the transmission protective systems to ensure the overall protection systems operates as designed. While the protective systems implemented on the individual generating units of dispersed power producing resources at these dispersed power producing facilities (i.e. individual wind turbines or solar panels/inverters) may in some cases need to be coordinated with other protective systems within the same dispersed power producing facility, new or changes to these protective systems do not need to be coordinated with the transmission protective systems, as this coordination would not provide reliability benefits to the BES.

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

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

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic

logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

M3. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

1.3. Data Retention

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

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

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

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

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

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

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~~TBD (balloted as~~ 1.1(~~X~~ii))	TBD	Adopted by the NERC Board of Trustees~~Standard revised in Project 2014-01~~	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

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Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

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   4.1. Balancing Authorities

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   4.3. Generator Operators

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

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

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

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

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

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

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

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

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

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

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

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by the NERC Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(i)	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
1.1(ii))	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 9, 2012	Adopted by Board of Trustees	Deleted Requirements R2, R5, and R6.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

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

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

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1 Generator Owner

   4.1.2 Transmission Owner that owns synchronous condenser(s)

   4.2. Facilities

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

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

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

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

   4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

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

5. Effective Date:

See the Implementation Plan for PRC-019-2.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

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

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

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

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the

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

voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

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

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

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

E. Regional Variances

None.

F. Associated Documents

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

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

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

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

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

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
2	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

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

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

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

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

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

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

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

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

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

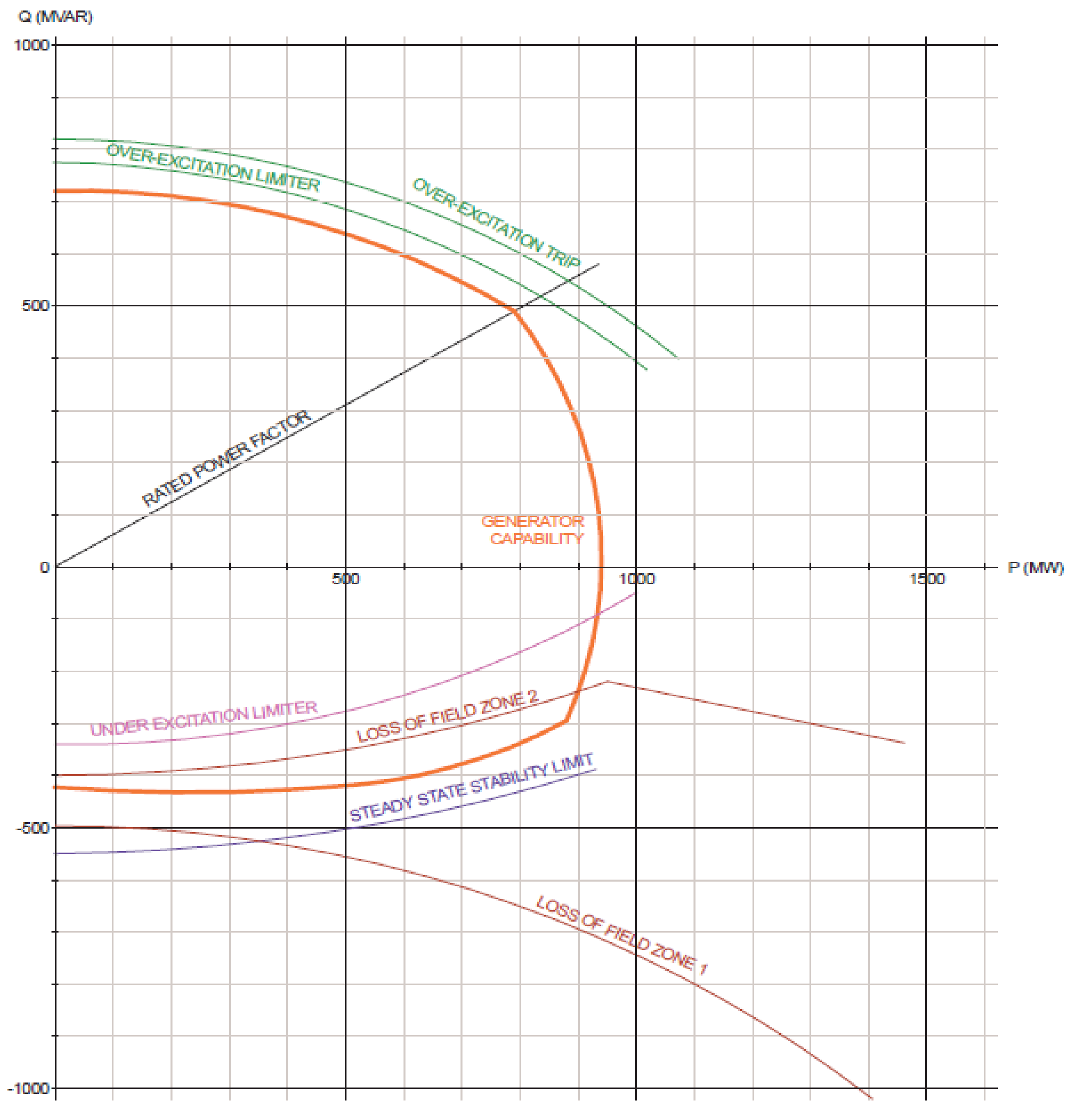
$R = V^2_g/2*(1/X_s+1/X_d)$

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

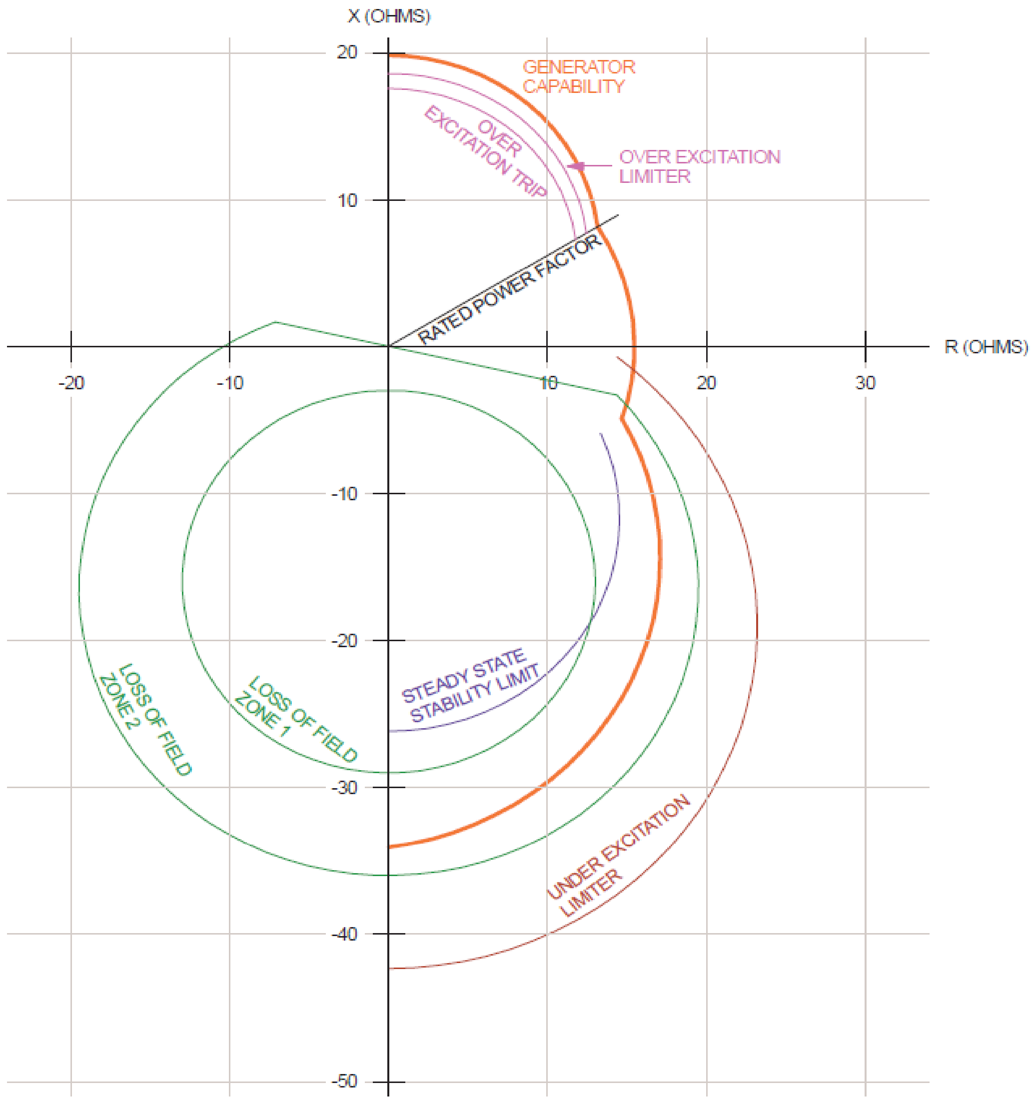
$C = (X_d-X_s)/2$

$R = (X_d+X_s)/2$

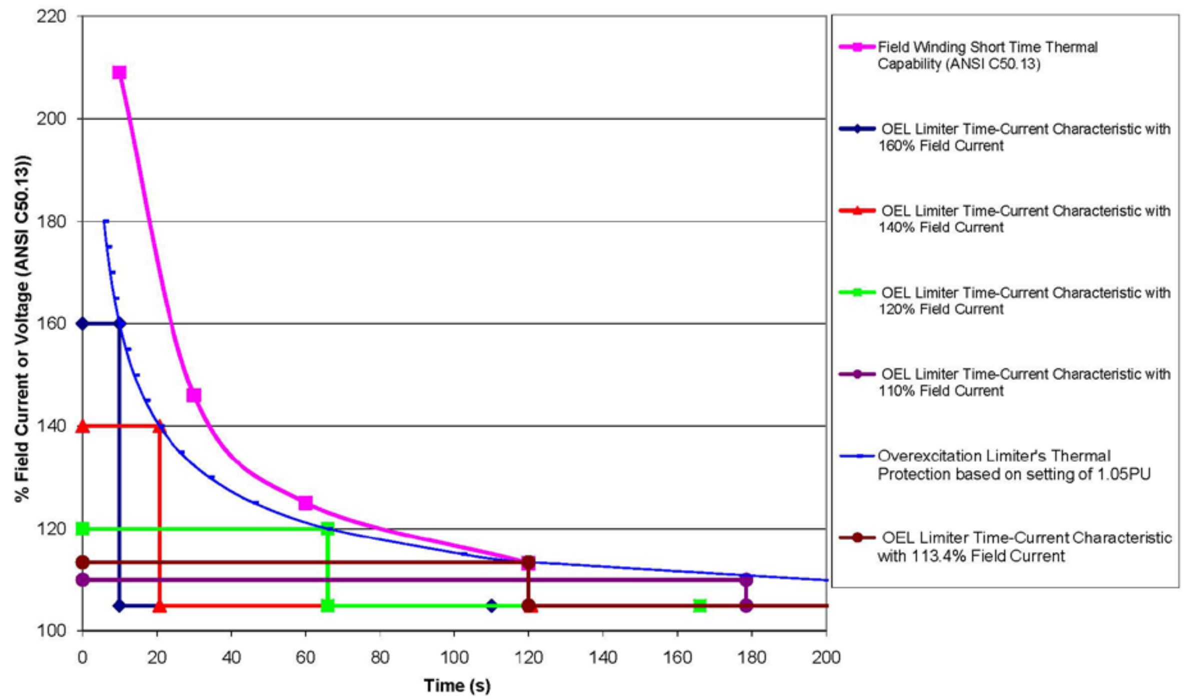
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. ~~2.~~ Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. ~~Given the timing of concurrent standards development of PRC projects, PRC-019-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-019. If this occurs, PRC-019-2 will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~December 2014~~
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

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

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

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

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

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

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

4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

> **Rationale for Facilities section 4.2.3.1**
>
> For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource ~~level~~. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

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

5. Effective Date:

See the Implementation Plan for PRC-019-2~~this standard~~.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

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

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

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

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the

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

voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

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

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

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

E. Regional Variances

None.

F. Associated Documents

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

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

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

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

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

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

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

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

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

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

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

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

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

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

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

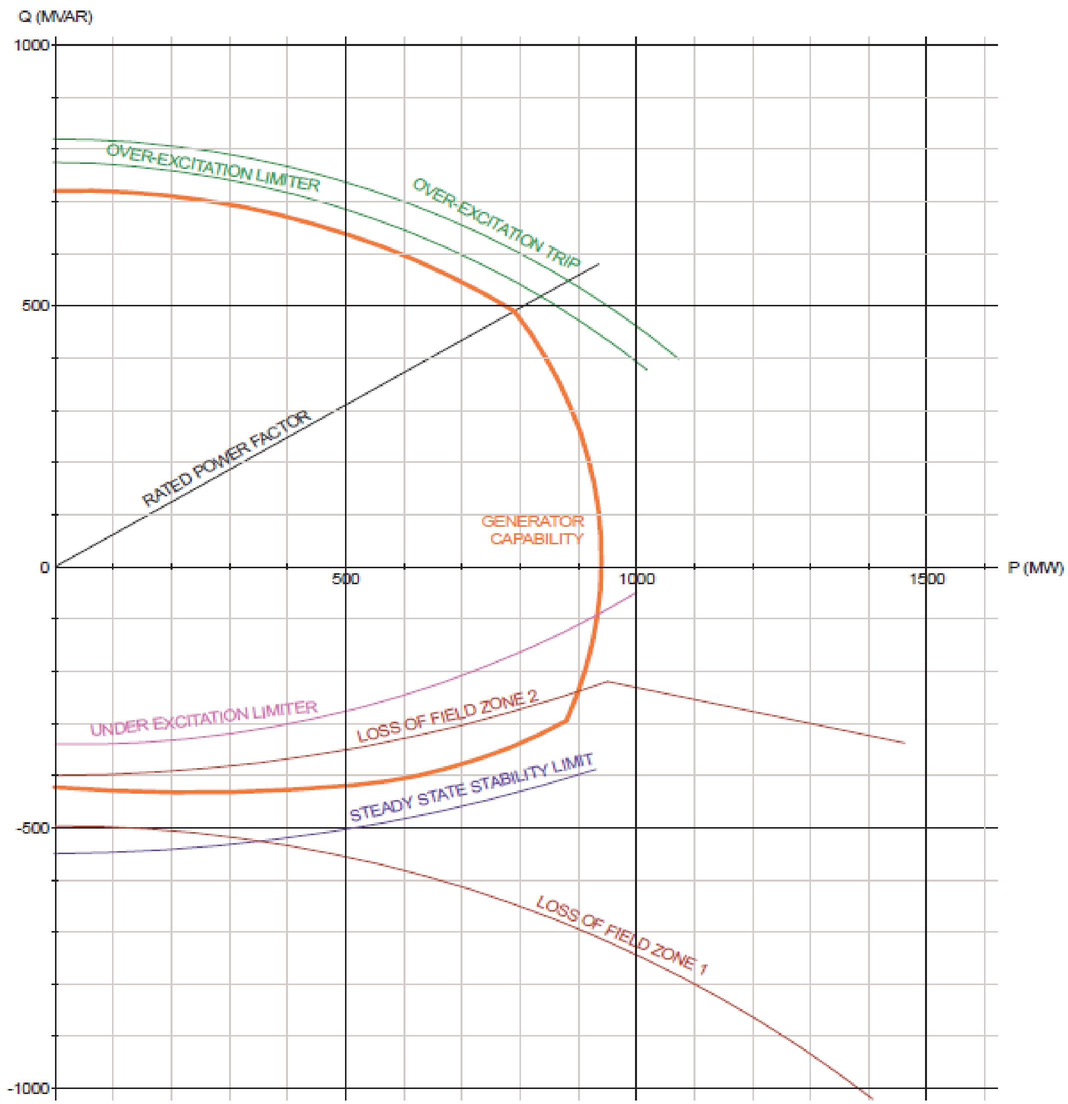
$R = V^2_g/2*(1/X_s+1/X_d)$

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

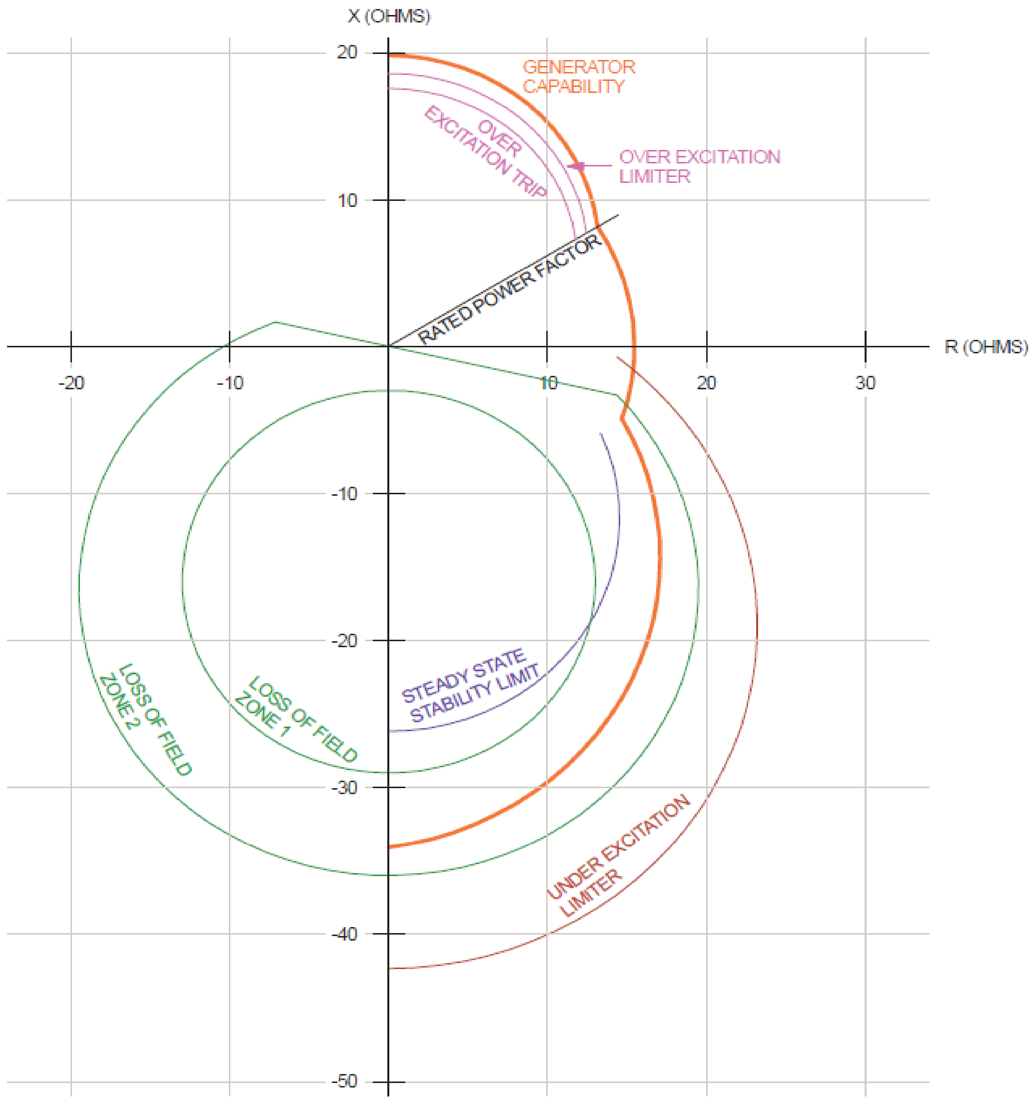
$C = (X_d-X_s)/2$

$R = (X_d+X_s)/2$

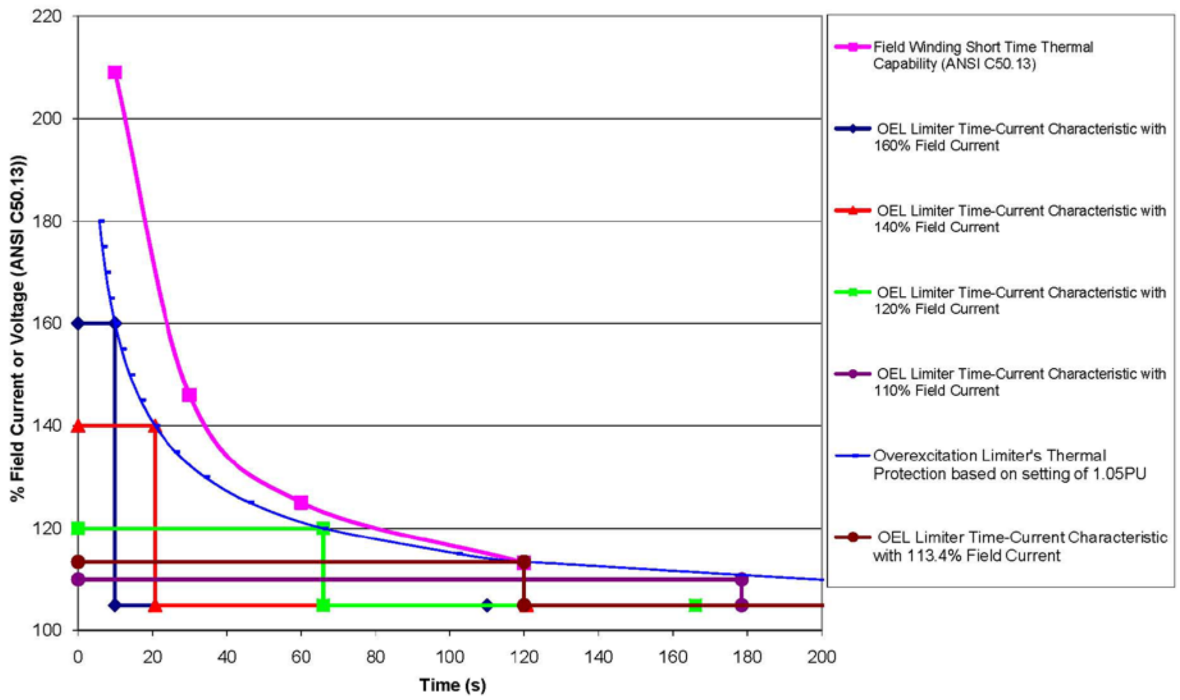
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-019-2 on November 5, 2014.

Description of Current Draft

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 – Standards Applicability for Dispersed Generation Resources standards drafting team has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[1]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

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

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

3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

4. **Applicability:**

4.1. Functional Entities

4.1.1 Generator Owner

4.1.2 Transmission Owner that owns synchronous condenser(s)

4.2. Facilities

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

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

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

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

4.2.3.1 This includes individual generating units of the dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition where voltage regulating control for the facility is performed solely at the individual generating unit of the dispersed power producing resources.

Rationale for Facilities section 4.2.3.1

For those dispersed power producing facilities that only perform voltage regulating control at the individual generating unit level, the SDT believes that coordination should take place at the individual generating unit level of the dispersed power producing resource ~~level~~. These facilities need to consider the Protection Systems at the individual units and their compatibility with the reactive and voltage limitations of the units. Where voltage regulating control is done at an aggregate level, applicability is already included under Facilities section 4.2.3.

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

5. Effective Date:

See the Implementation Plan for PRC-019-2~~this standard~~.

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

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

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

~~**5.1.3** By the first day of the first calendar quarter, four calendar years following applicable regulatory, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.~~

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

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

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

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

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

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

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service[2] limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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

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

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

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

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

C. Measures

M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service[3] limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

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

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

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment

	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	identification or implementation of a change in equipment or settings that affected the coordination.	or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

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

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

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

"IEEE C37.102-2006 IEEE Guide for AC Generator Protection"

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

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-019-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. Reference

Examples of Coordination

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

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

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

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

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

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

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

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

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

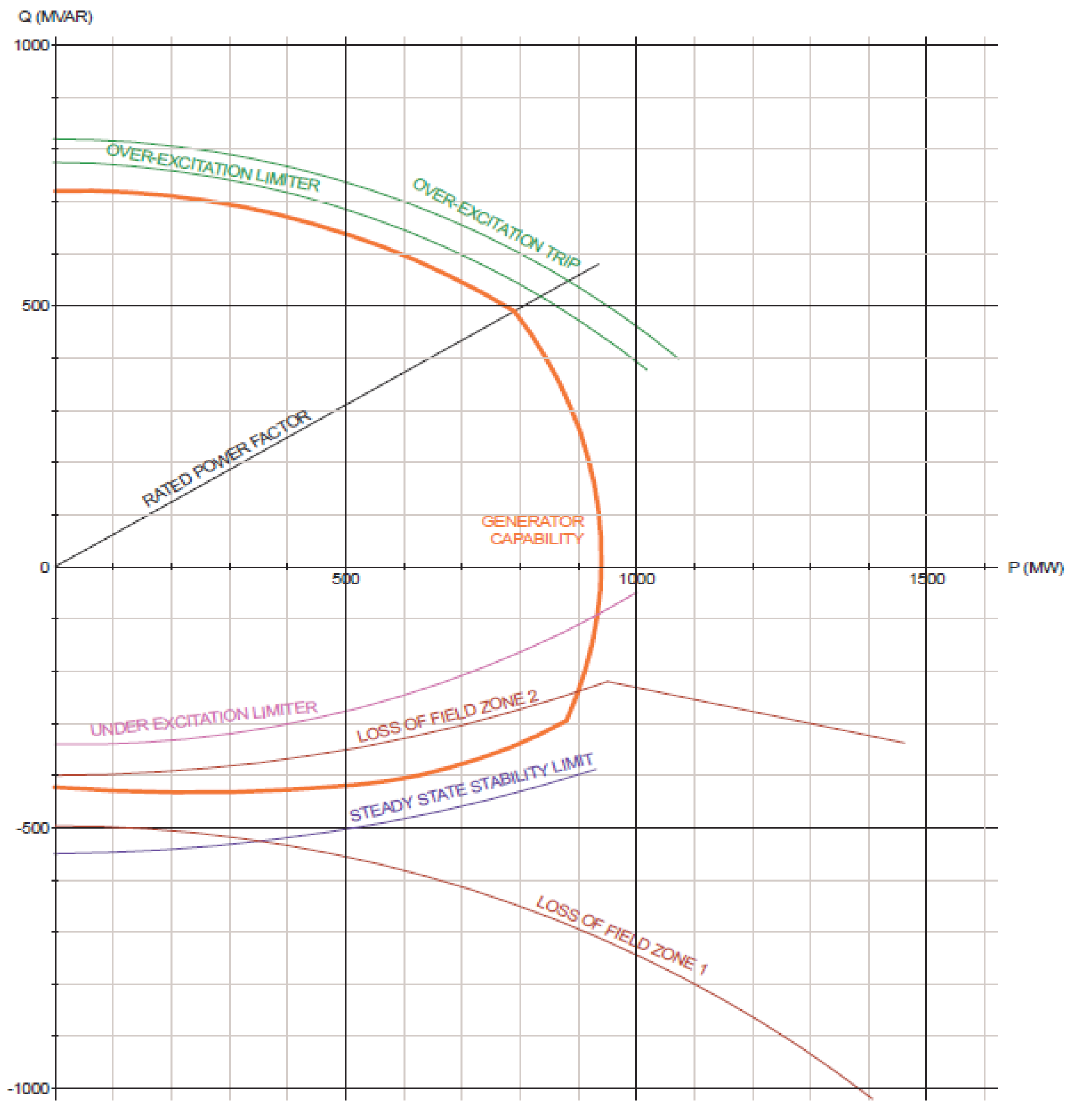
$$R = V^2_g/2*(1/X_s+1/X_d)$$

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

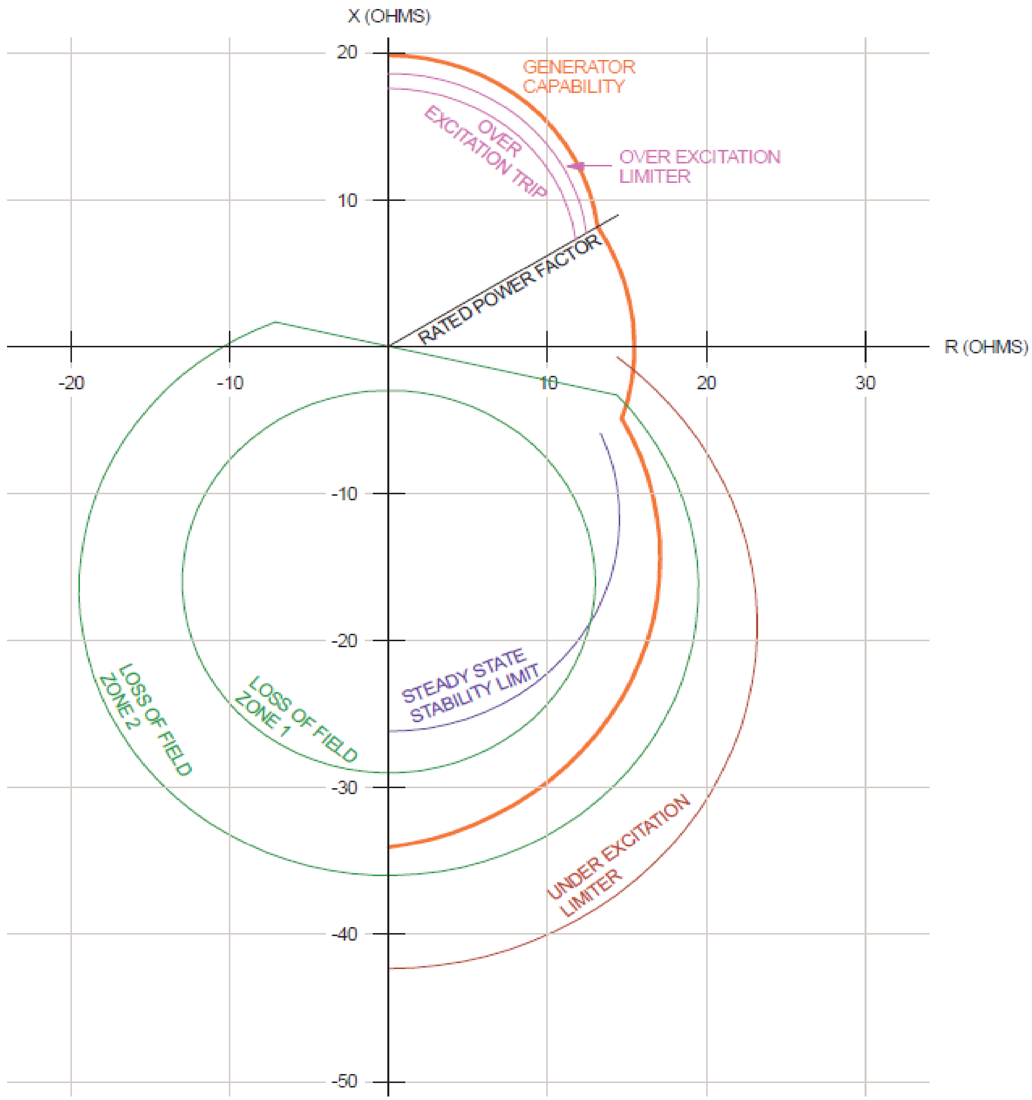
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

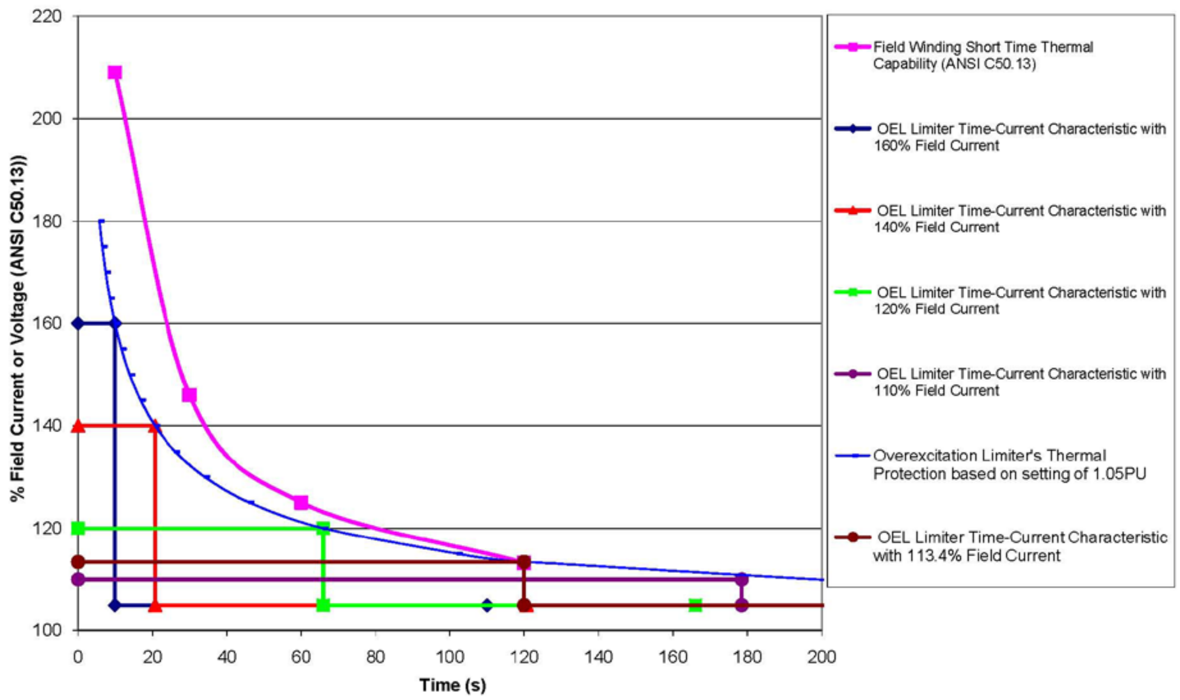
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



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



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



Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-2[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.

[2] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**

   4.1. Generator Owner
5. **Effective Date:**

   See the Implementation Plan for PRC-024-2.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

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[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

Rationale for Footnotes 4 and 6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

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[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

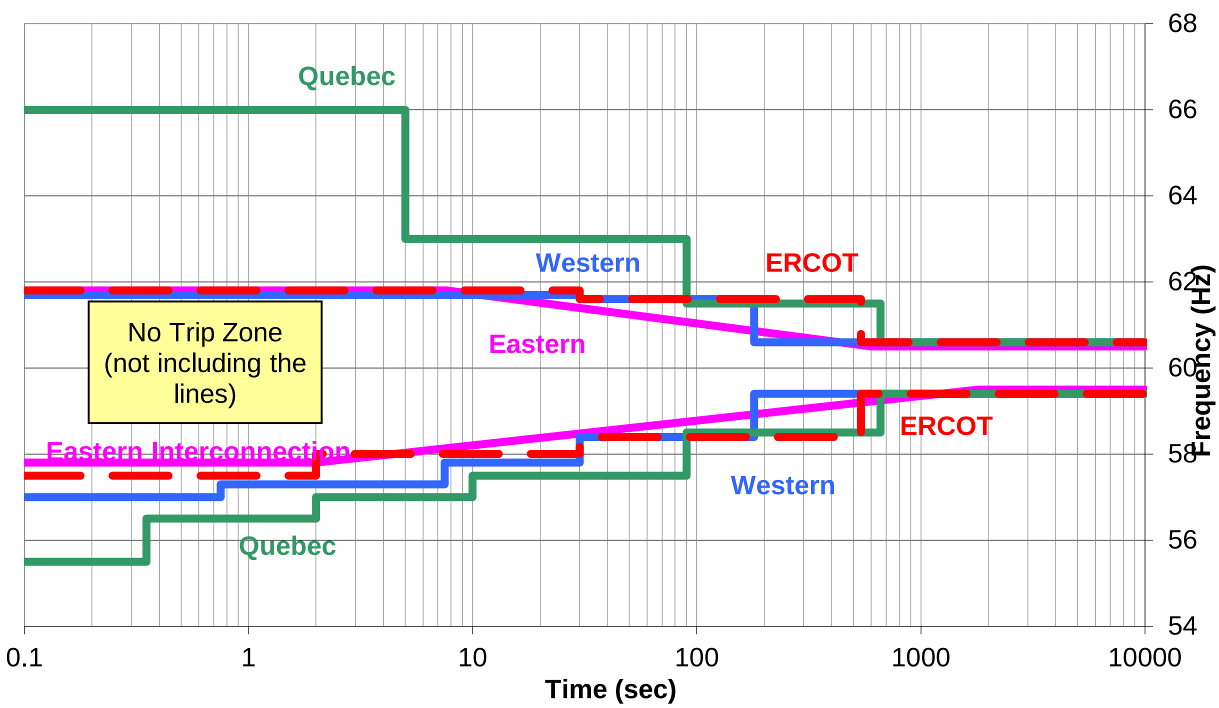
2	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

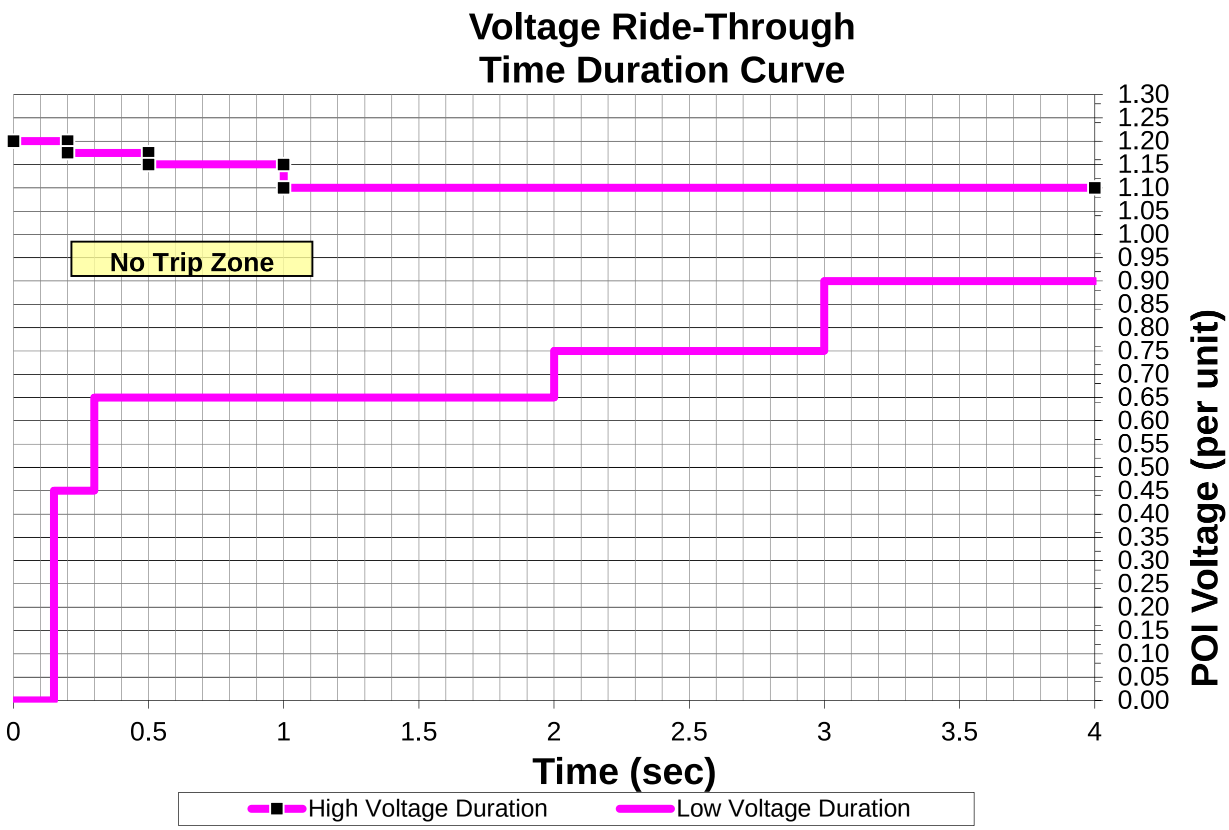
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
3. Initial posting of revised standard PRC-024-2 on November 5, 2014.

Description of Current Draft

PRC-024-2~~1(X)~~[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. ~~Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
~~45-day Additional Formal Comment Period with Additional Ballot (if necessary)~~	~~December 2014~~
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.~~currently includes an (X) to indicate the version numbering will be updated . Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2~~1(X)~~
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
   4.1. Generator Owner
5. **Effective Date:**
   See the Implementation Plan for PRC-024-2~~this standard~~.

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

Rationale for Footnotes ~~2~~ 4 and ~~4~~6

The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting ~~within~~ the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

[6] For voltage protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

3.1. The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

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[7] Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

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

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

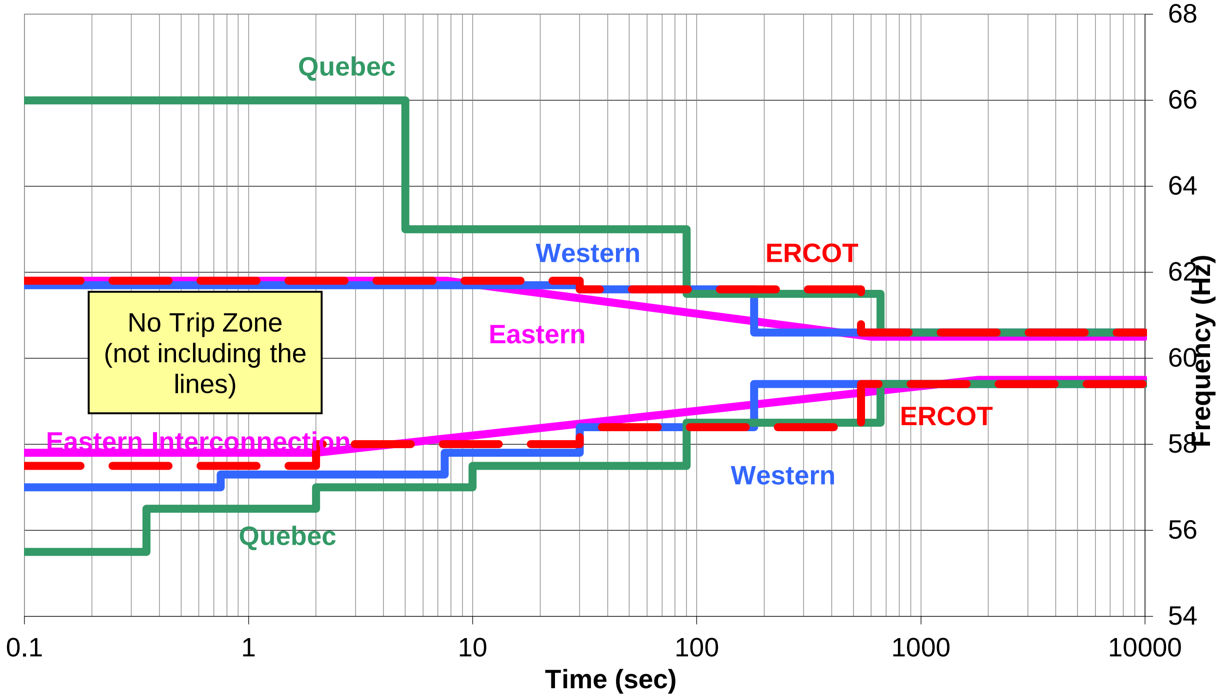
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

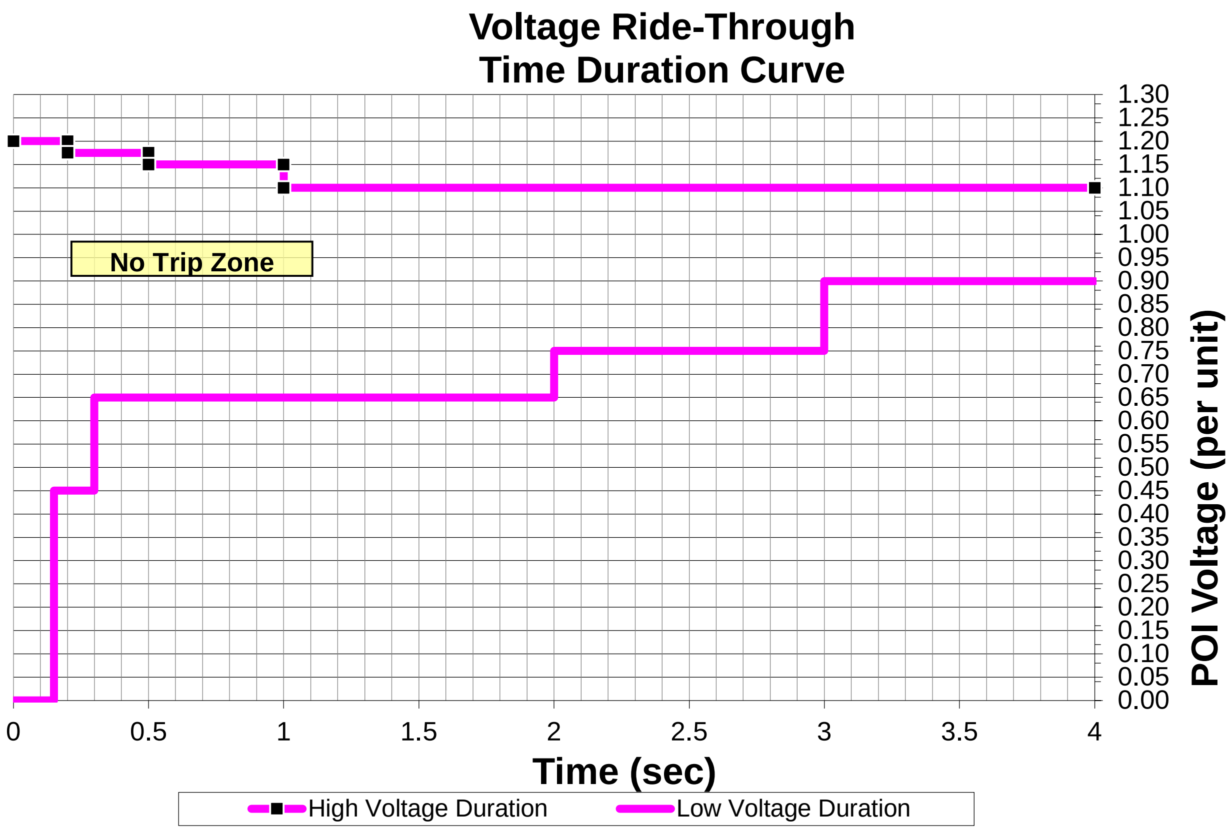
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (Sec)**
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	**Time (sec)**	**Voltage (pu)**	**Time (sec)**
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
   a. All of the units connected to the same transformer are online and operating.
   b. All of the units are at full nameplate real-power output.
   c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
   d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment November 20 – December 19, 2013.
2. The Standards Committee authorized this posting on September 30, 2014.
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Description of Current Draft

PRC-024-2~~1(X)~~[1] is proposed for approval to align the applicability section of PRC-024-1 with the revised definition of the Bulk Electric System (BES). Specifically, the Project 2014-01 –Standards Applicability for Dispersed Generation Resources standards drafting team recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. ~~Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.~~ Project 2014-01 does not have in its scope any technical content changes beyond revising the applicability to ensure consistent application of the requirements of this standard to dispersed power producing resources.[2]

Anticipated Actions	Anticipated Date
Final ballot	January 2015
BOT adoption	February 2015

[1] The standard version number included an (X) to indicate the version numbering would be updated, and NERC has since assigned the appropriate version number prior to final ballot.~~currently had includes an (X) to indicate the version numbering will be updated, and . Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will since assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

[2] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

When this standard has received ballot approval, the text boxes within the Applicability section of the standard will be moved to the Application Guidelines Section of the standard.

A. Introduction

1. **Title:** **Generator Frequency and Voltage Protective Relay Settings**
2. **Number:** PRC-024-2~~1~~(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
   4.1. Generator Owner
5. **Effective Date:**

   See the Implementation Plan for PRC-024-2~~this standard.~~

~~In those jurisdictions where regulatory approval is required:~~

~~By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~In those jurisdictions where regulatory approval is not required:~~

~~By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

~~By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.~~

B. Requirements

R1. Each Generator Owner that has generator frequency protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no trip zone" of PRC-024 Attachment 1, subject to the following exceptions:[4] *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Rationale for Footnotes ~~2~~4 and 46 The SDT has determined it is appropriate to require that protective relay settings applied on both the individual generating units and aggregating equipment (including any non-Bulk Electric System collection system equipment) are set respecting~~within~~ the "no-trip zone" referenced in the requirements to maintain reliability of the BES. If any of the protective relay settings applied on these elements of the facility were to be excluded from this standard, the potential would exist for portions of or the entire generating capacity of the dispersed power producing facility to be lost during a voltage or frequency excursion.

R2. Each Generator Owner that has generator voltage protective relaying[3] activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a

[3] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

[4] For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.

voltage excursion (at the point of interconnection[5]) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2.[6] If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
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- Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
- Generating unit(s) may trip within a portion of the "no trip zone" of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

R3. Each Generator Owner shall document each known regulatory or equipment limitation[7] that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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[5] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

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R4. Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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M1. Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.

M2. Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.

M3. Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

M4. Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

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1.1. Compliance Enforcement Authority

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

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

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

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

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Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

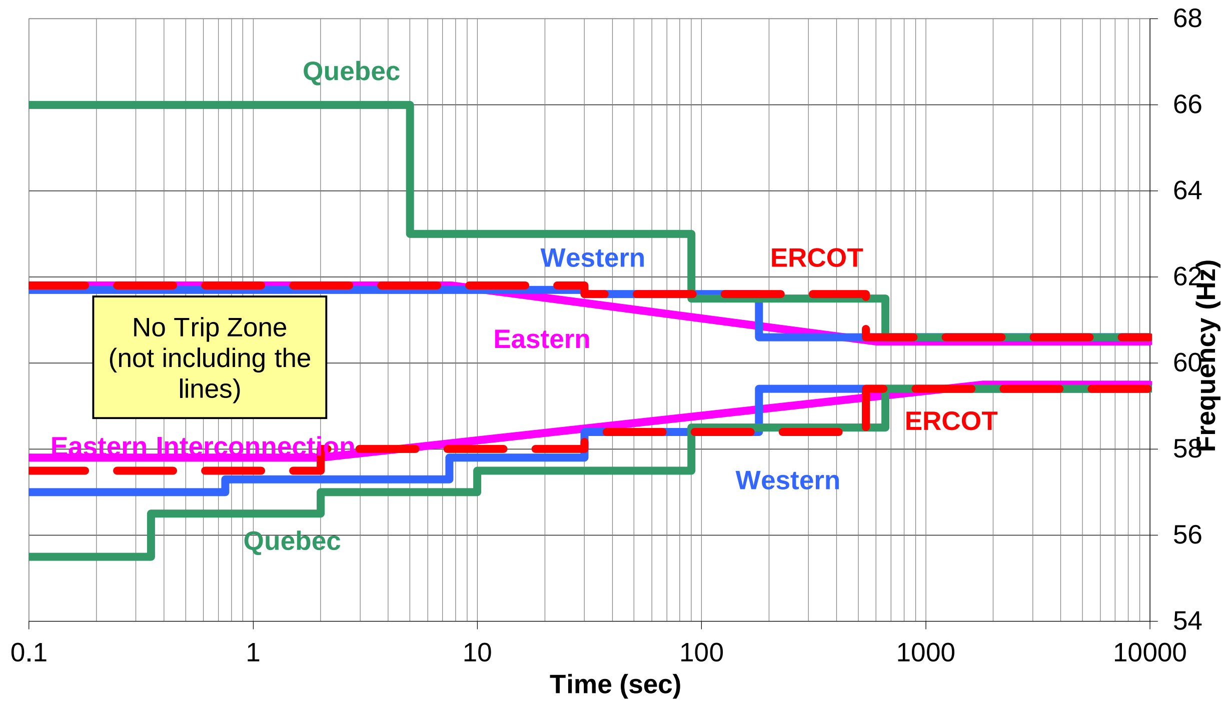
~~1~~	~~March 20, 2014~~	~~FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)~~	
2	TBD	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources

G. References

1. "The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF)," dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Time (Sec)**	**Frequency (Hz)**	**Time (sec)**
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

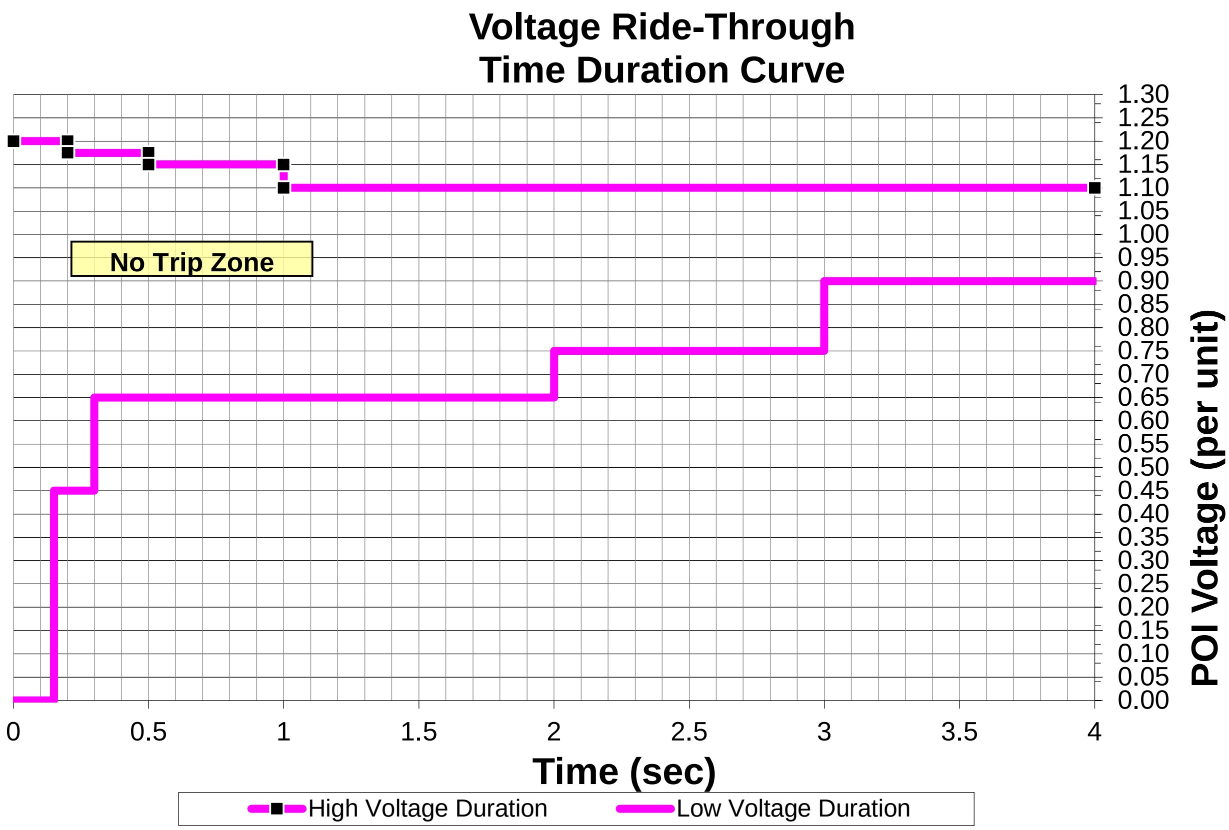
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
    a. All of the units connected to the same transformer are online and operating.
    b. All of the units are at full nameplate real-power output.
    c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
    d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Implementation Plan
Dispersed Generation Resources
PRC-001-1.1(ii)

Standards Involved
Approval:

- PRC-001-1.1(ii) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i))

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations
PRC-001-1.1(ii) is proposed for approval to align the applicability of PRC-001-1.1 with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources.

Effective Date
PRC-001-1.1(ii) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable

[1] The terms “dispersed generation resources” and “dispersed power producing resources” are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1 (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i)), shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(ii).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

Implementation Plan

Dispersed Generation Resources
PRC-001-1.1(~~X~~ii)

~~The standard version number currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

Standards Involved

Approval:

- PRC-001-1.1(~~X~~ii) – System Protection Coordination

Retirement:

- PRC-001-1.1a – System Protection Coordination (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i))

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-001, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-001-1.1(~~X~~ii) is proposed for approval to align the applicability of PRC-001-1.1~~a~~ with the revised definition of the BES. Specifically, the SDT has coordinated with the other SDTs currently reviewing this standard and has recommended revisions to Requirement R3.1 to account for the unique characteristics of dispersed power producing resources. ~~Given the timing of concurrent standards development of PRC, TRP, and IRO projects, PRC-001-1.1a may be retired pursuant to an Implementation Plan of a successor version of PRC-001. If this occurs, PRC-001-1.1(X) will not go into effect.~~

Effective Date

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

PRC-001-1.1(~~X~~ii) shall become effective immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-001-1.1~~a~~ (or a successor version of PRC-001-1.1 such as PRC-001-1.1(i)), shall be retired at midnight of the day immediately prior to the Effective Date of PRC-001-1.1(~~X~~ii).

Applicability:

This standard applies to the following functional entities:

- Transmission Operator
- Generator Operator
- Balancing Authority

Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved
Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:
N/A

Background
In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations
PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements.

Effective Date

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

PRC-019-2 shall become effective on the later of the first day following the Effective Date of PRC-019-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-019-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of “Bulk Electric System” is available here.

The Implementation Plan for PRC-019-1 is available here.

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RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-019-2

Standards Involved

Approval:

- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Retirement:

- PRC-019-1 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability sections of certain Reliability Standards, including PRC-019, are necessary to align the standards with the implementation of the revised BES definition. The standard drafting team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section and requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed power producing resources in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.[1]

General Considerations

PRC-019-2 is proposed for approval to align the applicability section of PRC-019-1 with the revised definition of the BES. Specifically, the SDT has recommended revisions to the Facilities section to clarify that facilities that solely regulate voltage at the individual generating unit are subject to the requirements. ~~Given the timing of concurrent standards development of PRC projects, PRC-019-1 may already be retired pursuant to an Implementation Plan of a successor version of PRC-. If this occurs, PRC-019-2 will not go into effect.~~

[1] The terms "dispersed generation resources" and "dispersed power producing resources" are used interchangeably in Project 2014-01 because the former term was used in the Standards Authorization Request for the project, while the latter term is in line with terminology used in the revised definition of the BES.

Effective Date

PRC-019-2 shall become effective on the later of the first day following the Effective Date of PRC-019-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-019-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-019-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-019-2.

Applicability:

This standard applies to the following functional entities:

- Transmission Owner that owns synchronous condenser(s)
- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-019-1 will remain applicable to PRC-019-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-019-1 is available here.

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Implementation Plan

Dispersed Generation Resources
PRC-024-2

Standards Involved

Approval:

- PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations

PRC-024-2 is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options.

Effective Date

PRC-024-2 shall become effective on the later of the first day following the Effective Date of PRC-024-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective Date of PRC-024-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-2.

Applicability:

This standard applies to the following functional entities:

- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Dispersed Generation Resources
PRC-024-~~1(X)~~2

~~The standard version numbers currently include an (X) to indicate the version numbering will be updated. Some standards are open in current projects and others are pending with governmental authorities. As a result, NERC will assign the appropriate version number prior to adoption by the NERC Board of Trustees.~~

Standards Involved

Approval:

- PRC-024-~~1(X)~~2 – Generator Frequency and Voltage Protective Relay Settings

Retirement:

- PRC-024-1 – Generator Frequency and Voltage Protective Relay Settings

Prerequisite Approvals:

N/A

Background

In light of the adoption of a revised Bulk Electric System (BES) definition by the NERC Board of Trustees, changes to the applicability of certain Reliability Standards, including PRC-024, are necessary to align the standards with the revised BES definition. The Standard Drafting Team (SDT) for Project 2014-01 – Standards Applicability for Dispersed Generation Resources has modified the applicability section or requirements of certain standards applicable to Generator Owners and Generator Operators to recognize the unique technical and reliability aspects of dispersed generation in order to ensure the applicability of the standards is consistent with the reliable operation of the BES.

General Considerations

PRC-024-~~1(X)~~2 is proposed for approval to align the applicability of PRC-024-1 with the revised definition of the BES. Specifically, the SDT recommended changes to the requirements addressing the scope of applicability and also recommended changes to the Reliability Standard Audit Worksheet to address documentation options. ~~Given the timing of concurrent standards development of PRC projects, PRC-024-1 may be retired pursuant to an Implementation Plan of a successor version of PRC-024. If this occurs, PRC-024-1(X) will not go into effect.~~

Effective Date

PRC-024-~~1(X)~~2 shall become effective on the later of the first day following the Effective Date of PRC-024-1 or immediately after the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the later of the first day following the Effective

Date of PRC-024-1 or the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

The existing standard, PRC-024-1, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-024-~~1(X)~~2.

Applicability:

This standard applies to the following functional entities:

- Generator Owner

Implementation Plan

All aspects of the Implementation Plan for PRC-024-1 will remain applicable to PRC-024-~~(X)~~2 and are incorporated here by reference.

Cross References

The Implementation Plan for the revised definition of "Bulk Electric System" is available here.

The Implementation Plan for PRC-024-1 is available here.

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard	
Title of Proposed Standard:	Application of certain GO/GOP Reliability Standards and Requirements to Dispersed Generation
Date Submitted:	10/1/2013

SAR Requester Information			
Name:	Jennifer Sterling-Exelon, Gary Kruempel-MidAmerican, Allen Schriver-NextEra Energy, Inc., Brian Evans-Mongeon-Utility Services Inc.		
Organization:	Exelon, MidAmerican, NextEra Energy, Utility Services Inc.		
Telephone:	(630) 437-2764 – primary contact	E-mail:	jennifer.sterling@exeloncorp.com primary contact

SAR Type (Check as many as applicable)	
☐ New Standard	☐ Withdrawal of existing Standard
☒ Revision to existing Standard	☐ Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The industry is requesting that the application section of certain GO/GOP Reliability Standards or the requirements of certain GO/GOP Reliability Standards be revised in order to ensure that the Reliability Standards are not imposing requirements on dispersed generation that are unnecessary and/or counterproductive to the reliable operation of the Bulk Electric System (BES). For purposes of this SAR, dispersed generation are those resources that aggregate to a total capacity greater than 75 MVA (gross

SAR Information
nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. This request is related to the proposed new definition of the Bulk Electric System (BES) from Project 2010-17, that results in the identification of elements of new dispersed generation facilities that if included under certain Reliability Standards may result in a detriment to reliability or be technically unsound and not useful to the support of the reliable operation of the BES .
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of the request is to revise the applicability of GO/GOP Reliability Standards or the Requirement(s) of GO/GOP Reliability Standards to recognize the unique technical and reliability aspects of dispersed generation, given the proposed new definition of the BES.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of the revisions to the applicability section and/or Requirements of certain GO/GOP Reliability Standards is to ensure that these revisions are approved by the Board of Trustees and applicable regulatory agencies prior to the effective date for newly identified elements under the proposed BES definition (i.e., June 2016).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The scope of this SAR involves revisions to the applicability section of the following GO/GOP Reliability Standard applicability sections and/or Reliability Standard Requirements: (a) PRC-005-2 (-3); (b) FAC-008-3; (c) PRC-023-3/PRC-025-1; (d) PRC-004-2a (-3) ; and (e) VAR-002-2 so it is clear what, if any, requirements should apply to dispersed generation. Also, IRO,MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities and reporting are conducted at the point of aggregation to 75 MVA, and not at an individual turbine, inverter or unit level for dispersed generation. This scope would also include development of a technical guidance paper for standard drafting teams developing new or revised Standards, so that they do not incorrectly apply requirements to dispersed generation unless such an application is technically sound and promotes the reliable operation of the BES. To the extent, there are existing Reliability Standard Drafting Teams that have the expertise and can make the requested changes prior to the compliance date of newly identified assets under the BES definition (i.e., June 2016), those projects may be assigned the required changes as opposed to creating new projects.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The following description and technical justification(including an assessment of reliability impacts) is provided for the standard drafting teams to execute the SAR for each applicable Standard.

PRC-005-2

Testing and maintenance of protection and control equipment for dispersed generation should start at the point of aggregation to 75 MVA. Manufacturers of dispersed generation turbines and solar panels recommend against specific testing and maintenance regimes for protection and control equipment at the dispersed generation turbine and panel level. In fact it is counterproductive to implement protection and control at the individual turbine, solar panel, or unit level. Instead this is best done at an aggregated level. Therefore, PRC-005 should indicate that the standard applies at the point of aggregation to at 75 MVA or greater for dispersed generation. This change would clarify that the facility section 4.2.5.3 is the section that would apply to dispersed generating facilities and that the remaining sections would not apply.

FAC-008-3

For dispersed generation, it is unclear if in FAC-008-3 the term “main step up transformer” refers to the padmount transformer at the base of the windmill tower or to the main aggregating transformer that steps up voltage to transmission system voltage. From a technical standpoint, it should be the point of aggregation at 75 MVA or above that is subject to this standard for dispersed generation, such as wind. It is at the point of aggregation at 75 MVA or above that facilities ratings should start, since it is this injection point at which a planner or operator of the system is relying on the amount of megawatts the dispersed generation is providing with consideration of the most limiting element. To require facility ratings at for each dispersed turbine, panel or generating unit is not useful to a planner or operator of the system, and, therefore, FAC-008-3 should be revised to be clear that facility ratings start at the point of aggregation at 75 MVA or above for dispersed generation.

SAR Information
Also consider that the BES definition specifically excludes collector system equipment at less than 75 MVA from being included in the BES. Thus, those portions of the collector systems that handle less than 75 MVA are not BES "Facilities," and, therefore, need not be evaluated per R1 or R2. Given this, there seems to be no technical value to conduct facility ratings for individual dispersed generation turbines, generating units and panels. **PRC-023-3/PRC-025-1** In keeping with the registration criteria for Generator Owners as well as the proposed BES Definition, the 75MVA point of aggregation should be the starting point for application of relay loadability requirements. **PRC-004-2** There is no technical basis to claim that misoperation analysis, corrective action plan implementation and reporting for dispersed generation at the turbine, generating unit or panel level is needed for the reliable operation of the BES. Similar to the statements above, the appropriate point to require misoperation analysis, corrective action plan implementation and reporting is at the point of aggregation at 75 MVA and above. **VAR-002-2** Voltage control for some types of dispersed generating facilities is accomplished by a controller that is able to adjust either generating unit controls or discrete reactive components to provide transmission system voltage adjustment. The VAR-002 standard should be modified to allow this type of control for dispersed generation facilities under the requirements of the standard. **General review of IROs, MODs, PRCs, TOPs** IRO, MOD, PRC or TOP Standards that require outage and protection and control coordination, planning, next day study or real time data or reporting of changes in real and reactive capability should be examined and revised, as needed, to ensure it is clear that these activities are conducted at the point of aggregation at 75 MVA, and not an individual turbine, generating unit or panel level for dispersed generation. Unless this clarity is provided applicability at a finer level of granularity related to dispersed generation may be seen as required and such granularity will result in activities that have no benefit to

SAR Information
reliable operation of the BES. Furthermore applicability at a finer level of granularity will result in uneeded and ineffective collection, analysis, and reporting activities that may result in a detriment to reliability.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☐ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.

Reliability Functions		
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes

Reliability and Market Interface Principles	
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
PRC-005-2, FAC-008-3, PRC-023-3/PRC-025-1/PRC-004-2a, VAR-002-2b and various IRO, MOD, PRC and TOP Standards	See explanation under technical analysis.

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(ii), PRC-019-2, and PRC-024-2

Final Ballots Now Open through January 22, 2015

Now Available

Final ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team are open through **8 p.m. Eastern, Thursday, January 22, 2015.**

The standards being balloted are:
- PRC-001-1.1(X) - System Protection Coordination
- PRC-019-2 - Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-024-1(X) - Generator Frequency and Voltage Protective Relay Settings

Background information for this project can be found on the project page.

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standards by clicking here.

Next Steps

The voting results for the standards will be posted and announced after the ballot window closes. If approved, they will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2014-01 Standards Applicability for Dispersed Generation Resources
PRC-001-1.1(ii), PRC-019-2, and PRC-024-2

Final Ballot Results

Now Available

Final ballots for three Project 2014-01 Standards Applicability for Dispersed Generation Resources medium-priority Reliability Standards as identified in the draft White Paper prepared by the Project 2014-01 drafting team concluded at **8 p.m. Eastern, Thursday, January 22, 2015.**

The standards are as follows:

- PRC-001-1.1(ii) – System Protection Coordination
- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-024-2 – Generator Frequency and Voltage Protective Relay Settings

The standards achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results	
Standard	**Quorum /Approval**
PRC-001-1.1(ii)	89.27% / 93.99%
PRC-019-2	89.30% / 94.03%
PRC-024-2	89.52% / 95.82%

Background information for this project can be found on the project page.

Next Steps
The standards will be submitted to the NERC Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Katherine Street, Standards Developer, or at 404-446-9702.

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3353 Peachtree Rd, NE
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Atlanta, GA 30326
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Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-001-1.1(ii)_Final_Ballot
Ballot Period:	1/13/2015 - 1/22/2015
Ballot Type:	Final
Total # Votes:	316
Total Ballot Pool:	354
Quorum:	**89.27 % The Quorum has been reached**
Weighted Segment Vote:	93.99 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	91	1	60	0.938	4	0.063	0	14	13
2 - Segment 2	8	0.4	4	0.4	0	0	0	2	2
3 - Segment 3	82	1	61	0.953	3	0.047	0	14	4
4 - Segment 4	27	1	20	1	0	0	0	6	1
5 - Segment 5	79	1	52	0.881	7	0.119	0	9	11
6 - Segment 6	52	1	37	0.925	3	0.075	0	7	5
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.5	4	0.4	1	0.1	0	0	0
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	6	0.5	5	0.5	0	0	0	0	1
Totals	**354**	**6.7**	**246**	**6.297**	**18**	**0.404**	**0**	**52**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	

1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Tacoma Power	John Merrell	Abstain	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Wind Energy Transmission Texas, LLC	Julius Horvath		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Negative	

3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Power	Marc Donaldson	Abstain	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	

4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Abstain	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Abstain	

5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Abstain	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Negative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	

6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	COMMENT RECEIVED
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Abstain	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Negative	
8		Debra R Warner	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-019-2_Final_Ballot
Ballot Period:	1/13/2015 - 1/22/2015
Ballot Type:	Final
Total # Votes:	317
Total Ballot Pool:	355
Quorum:	**89.30 % The Quorum has been reached**
Weighted Segment Vote:	94.03 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	91	1	60	0.938	4	0.063	0	15	12
2 - Segment 2	7	0.2	1	0.1	1	0.1	0	3	2
3 - Segment 3	83	1	61	0.968	2	0.032	0	15	5
4 - Segment 4	27	1	20	0.952	1	0.048	0	5	1
5 - Segment 5	79	1	52	0.897	6	0.103	0	10	11
6 - Segment 6	52	1	39	0.951	2	0.049	0	6	5
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	5	0.5	5	0.5	0	0	0	0	0
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	7	0.6	6	0.6	0	0	0	0	1
Totals	**355**	**6.6**	**247**	**6.206**	**16**	**0.395**	**0**	**54**	**38**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	

1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Tacoma Power	John Merrell	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Negative	COMMENT RECEIVED
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	

3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	

4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Abstain	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Affirmative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Negative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		

5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
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6	Con Edison Company of New York	David Balban	Affirmative	
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6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	

6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Texas Reliability Entity, Inc.	Derrick Davis	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2014-01-DGR-PRC-024-2_Final_Ballot
Ballot Period:	1/13/2015 - 1/22/2015
Ballot Type:	Final
Total # Votes:	316
Total Ballot Pool:	353
Quorum:	**89.52 % The Quorum has been reached**
Weighted Segment Vote:	95.82 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	90	1	58	0.935	4	0.065	0	16	12
2 - Segment 2	7	0.2	2	0.2	0	0	0	3	2
3 - Segment 3	82	1	59	0.937	4	0.063	0	15	4
4 - Segment 4	27	1	20	0.952	1	0.048	0	5	1
5 - Segment 5	79	1	56	0.949	3	0.051	0	9	11
6 - Segment 6	52	1	39	0.951	2	0.049	0	6	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.5	5	0.5	0	0	0	0	0
9 - Segment 9	3	0.3	3	0.3	0	0	0	0	0

10 - Segment 10	6	0.5	5	0.5	0	0	0	0	1
Totals	**353**	**6.6**	**248**	**6.324**	**14**	**0.276**	**0**	**54**	**37**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson		
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Glenn Pressler	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Larry Nash	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Abstain	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Abstain	
1	Idaho Power Company	Molly Devine	Abstain	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Daniel Gibson		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Mike Smith	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	

1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Joseph A Smith	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Steven C Cobb	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Tacoma Power	John Merrell	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Steven Johnson		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Corp.	David J Jendras	Affirmative	
3	APS	Sarah Kist		
3	Associated Electric Cooperative, Inc.	Todd Bennett	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	Basin Electric Power Cooperative	Jeremy Voll	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Beaches Energy Services	Steven Lancaster	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Leesburg	Chris Adkins	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	

3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	DTE Electric	Kent Kujala	Abstain	
3	FirstEnergy Corp.	Richard S Hoag	Affirmative	
3	Florida Keys Electric Cooperative	Tom B Anthony	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Fort Pierce Utilities Authority	Thomas Parker	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	Ayesha Sabouba	Abstain	
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Seth Shoemaker	Affirmative	
3	N.W. Electric Power Cooperative, Inc.	John Stickley	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Andrea Basinski	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	

4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Abstain	
4	DTE Electric	Daniel Herring	Abstain	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Fort Pierce Utilities Authority	Javier Cisneros	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Keys Energy Services	Stan T Rzad	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	American Electric Power	Thomas Foltz	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke		
5	Basin Electric Power Cooperative	Mike Kraft	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Dairyland Power Coop.	Tommy Drea		
5	Dominion Resources Services	Randall C Heise	Negative	
5	DTE Electric	Mark Stefaniak	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	EDP Renewables North America LLC	Heather Bowden	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	Ingleside Cogeneration LP	Michelle R DAntuono	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Abstain	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tennessee Valley Authority	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Missouri	Robert Quinlivan	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	New York State Electric & Gas Corp.	Julie S King	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	

6	Oglethorpe Power Corporation	Donna Johnson	Affirmative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	Powerex Corp.	Gordon Dobson-Mack		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	COMMENT RECEIVED
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
6	Westar Energy	Tiffany Lake	Affirmative	
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
7	Occidental Chemical	Venona Greaff	Affirmative	
8		David L Kiguel	Affirmative	
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	City of Vero Beach	Ginny Beigel	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Bob Reynolds		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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