UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _________**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF ERRATA TO VOLTAGE AND REACTIVE CONTROL RELIABILITY STANDARDS

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August 18, 2017

TABLE OF CONTENTS

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval errata to the following two mandatory and enforceable Voltage and Reactive Control ("VAR") Reliability Standards, which were reaffirmed by the NERC Board of Trustees at its August 10, 2017 meeting:[4]

- VAR-001-4.1 (Voltage and Reactive Control); and
- VAR-002-4 (Generator Operation for Maintaining Network Schedules).

In addition, NERC requests Commission approval of an errata to the following mandatory and enforceable regional Reliability Standard for the Western Electricity Coordinating Council ("WECC") region:

- VAR-501-WECC-3 (Power System Stabilizer).

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1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2017).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 This filing serves as notice to the Commission of the reaffirmation of the standards.

Clean and redline versions of proposed Reliability Standards VAR-001-4.2, VAR-002-4.1, and VAR-501-WECC-3.1 are attached to this petition as **Exhibits A, B, and C,** respectively.

I. BACKGROUND

A. Periodic Review of VAR-001-4.1 and VAR-002-4

NERC conducts periodic reviews of Reliability Standards in accordance with Section 317 of the NERC Rules of Procedure and Section 13 of the NERC Standard Processes Manual.[5] In accordance with these authorities and the NERC *Reliability Standards Development Plan: 2017-2019*,[6] NERC recently completed Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Reliability Standards.[7] This project conducted a periodic review of mandatory and enforceable Reliability Standards VAR-001-4.1 (Voltage and Reactive Control)[8] and VAR-002-4 (Generator Operation for Maintaining Network Schedules).[9]

The periodic review team found that the two VAR Reliability Standards are sufficient to protect reliability, each meets its reliability objective, and that no immediate substantive revisions are necessary. However, the team found that there may be future opportunity to improve non-substantive or insignificant quality and content issues. Based on the results of its review, the periodic review team recommended reaffirming the Reliability Standards. The NERC

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5 The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

6 NERC filed the *Reliability Standards Development Plan: 2017-2019* on December 16, 2016 in Docket Nos. RM05-17-000, RM05-25-000, and RM06-16-000.

7 More information about this project is available on the Project 2016-EPR-02 project page, http://www.nerc.com/pa/Stand/Pages/Project-2016-EPR-02-Enhanced-Periodic-Review-of-Voltage-and-Reactive-Standards.aspx.

8 The Commission approved Reliability Standard VAR-001-4 (Voltage and Reactive Control) on August 1, 2014.*See North American Electric Reliability Corp.*, Docket No. RD14-11-000 (Aug. 1, 2014) (delegated letter order). The Commission approved errata version VAR-001-4.1 on November 13, 2015. *See North American Electric Reliability Corp.*, Docket No. RD15-6-000 (Nov. 13, 2015) (delegated letter order).

9 The Commission approved Reliability Standard VAR-002-4, which clarified the applicability of the VAR-002 standard to dispersed generation resources, on May 29, 2015. *See North American Electric Reliability Corp*, 151 FERC ¶ 61,186 (May 29, 2015).

Standards Committee accepted this recommendation at its June 14, 2017 meeting, and on August 10, 2017, the NERC Board of Trustees voted to adopt the reaffirmed VAR Reliability Standards.

In the course of its work, the periodic review team identified and recommended changes to correct errata in VAR-001-4.1 and VAR-002-4. In accordance with Section 12 of the NERC Standard Processes Manual, the NERC Standards Committee approved the proposed errata changes on June 14, 2017. The proposed errata changes are described in Section III below.

B. Regional Reliability Standard VAR-501-WECC-3

The Commission approved WECC regional Reliability Standard VAR-501-WECC-3 (Power System Stabilizer) on April 28, 2017.[10] Following approval of the standard, non-substantive errors were identified in the Violation Severity Levels and Guidelines and Technical Basis sections. In accordance with the WECC Reliability Standards Development Procedures and Section 12 of the NERC Standard Processes Manual, the NERC Standards Committee approved the proposed errata on July 19, 2017.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[11]

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10 *North American Electric Reliability Corp.*, Docket No. RD17-5-000 (Apr. 28, 2017) (delegated letter order).

11 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2017), to allow the inclusion of more than two persons on the service list in this proceeding.

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III. <u>ERRATA</u>

This section describes the proposed errata changes reflected in Reliability Standards VAR-001-4.2, VAR-002-4.1, and VAR-501-WECC-3.1. Pursuant to Section 12 of the NERC Standard Processes Manual, none of the proposed errata change the scope or intent of the associated Reliability Standard, nor do any of the changes have any material impact on the end users of the associated Reliability Standard.

A. Proposed Reliability Standard VAR-001-4.2

The errata reflected in the proposed standard include: (i) corrections to the name of the time horizon from “Operational Planning” to “Operations Planning” throughout; (ii) clarification in Measure M1 that the time for required action is within “30 <u>calendar</u> days,” in accordance with the corresponding Requirement; (iii) clarification, in Measure M3, that the entity’s evidence may include, <u>but is not limited to</u>, the specified items*;* (iv) correction of grammar in Requirement R4 and the corresponding Measure M4; and (v) corrected capitalization of non-defined terms in Measure M5, WECC Regional Variance Requirement E.A.18, and in the Guidelines and Technical Basis section.

B. Proposed Reliability Standard VAR-002-4.1

The erratum reflected in the proposed standard corrects the capitalization of the defined term “Reactive Power” in Requirement R2, footnote 4.

C. Proposed Regional Reliability Standard VAR-501-WECC-3.1

The errata reflected in the proposed standard consists of corrections to the Violation Severity Levels and Guidelines and Technical Basis for Requirement R1. The reference to the entity that receives documentation is corrected from “Transmission Planner” to “Transmission Operator” to correspond to the language of the Requirement.

IV. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve the proposed errata to the Reliability Standards included in **Exhibits A, B, and C.**

Respectfully submitted,

/s/ Lauren A. Perotti

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August 18, 2017

Exhibit A

Proposed Reliability Standard VAR-001-4.2 (Voltage and Reactive Control)

Exhibit A-1

Proposed Reliability Standard VAR-001-4.2 Clean

A. Introduction

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

2. **Number:** VAR-001-4.2

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

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

B. Requirements and Measures

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

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

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

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

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

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

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

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None

Table of Compliance Elements

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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

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

Requirements

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

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

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

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

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

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

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

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

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

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

Measures[1]

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

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

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

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

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

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

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

Violation Severity Levels

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

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.2	August 10, 2017	Adopted by NERC Board of Trustees	Errata

Guidelines and Technical Basis

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

Rationale:

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

Rationale for R1:

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

Rationale for R2:

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

Rationale for R3:

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

Rationale for R4:

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

Rationale for R5:

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

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

Rationale for R6:

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

Exhibit A-2

Proposed Reliability Standard VAR-001-4.2 Redline

A. Introduction

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

2. **Number:** VAR-001-4.~~1~~2

3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Transmission Operators

   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. **Effective Date:**

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

B. Requirements and Measures

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

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

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

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

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

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

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

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

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

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

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

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

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

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

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

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

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

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

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

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

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

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None

Table of Compliance Elements

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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Operations Planning**	**Lower**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.

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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

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

Requirements

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

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

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

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

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

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

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

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

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

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

Measures[1]

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

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

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

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

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

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

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

Violation Severity Levels

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

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added “Generator Owners” and “Generator Operators” to Applicability section.	Errata
1	August 23, 2007	Removed “Generator Owners” and “Generator Operators” to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	
4.1	August 25, 2015	Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power	Errata
4.1	November 13, 2015	FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000	Errata
4.2	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata

4.2	August 10, 2017	~~FERC~~ Adopted by NERC Board of Trustees	Errata

Guidelines and Technical Basis

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

Rationale:

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

Rationale for R1:

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

Rationale for R2:

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

Rationale for R3:

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

Rationale for R4:

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

Rationale for R5:

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

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

Rationale for R6:

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

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~~4.1~~	~~August 25, 2015~~	~~Added "or" to Requirement R5, 5.3 to read: schedules or Reactive Power~~	~~Errata~~
~~4.1~~	~~November 13, 2015~~	~~FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000~~	~~Errata~~

Exhibit B

Proposed Reliability Standard VAR-002-4.1 (Generator Operation for Maintaining Network Schedules)

Exhibit B-1

Proposed Reliability Standard VAR-002-4.1 Clean

A. Introduction

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

    See Implementation Plan.

B. Requirements and Measures

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

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

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

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

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

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

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

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

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

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

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

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

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, Reactive Power capability may change based on stability considerations.

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

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

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

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

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

5.1. For generator step-up and auxiliary transformers5 with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

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

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

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

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

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

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Real-time Operations	Medium	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any explanation.
R3	Real-time Operations	Medium	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications. OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	4/16/2013	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.	Revised
3	5/5/2014	Revised under Project 2013-04 to address outstanding Order 693 directives.	Revised
3	5/7/2014	Adopted by NERC Board of Trustees	
3	8/1/2014	Approved by FERC in docket RD14-11-000	
4	8/27/2014	Revised under Project 2014-01 to clarify applicability of Requirements to	Revised

		BES dispersed power producing resources.	
4	11/13/2014	Adopted by NERC Board of Trustees	
4	5/29/2015	FERC Letter Order in Docket No. RD15-3-000 approving VAR-002-4	
4.1	June 14, 2017	Project 2016-EPR-02 errata recommendations	Errata
4.1	August 10, 2017	Adopted by the NERC Board of Trustees	Errata

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 R1:

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

Rationale for R2:

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

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

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

Rationale for R3:

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

Rationale for R4:

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

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

Rationale for R5:

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

Rationale for Exclusion in R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR- 002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

Rationale for R6:

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

Exhibit B-2

Proposed Reliability Standard VAR-002-4.1 Redline

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**

2. **Number:** **VAR-002-4.1**

3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Generator Operator

   4.2. Generator Owner

5. **Effective Dates**

   See Implementation Plan.

B. Requirements and Measures

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

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

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

[1] Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
[2] Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

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

2.1. When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

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

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

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.

Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

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

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

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

[3] The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

[4] Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, ~~reactive power~~Reactive Power capability may change based on stability considerations.

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

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

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

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

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

5.1. For generator step-up and auxiliary transformers5 with primary voltages equal to or greater than the generator terminal voltage:

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

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

[5] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

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

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

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

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations**	**Medium**	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any explanation.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator's specifications. OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

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		BES dispersed power producing resources.	
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Rationale:

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Rationale for R2:

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Rationale for R3:

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

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

Rationale for Exclusion in R4:

VAR-002 addresses control and management of reactive resources and provides voltage control where it has an impact on the BES. For dispersed power producing resources as identified in Inclusion I4, Requirement R4 should not apply at the individual generator level due to the unique characteristics and small scale of individual dispersed power producing resources. In addition, other standards such as proposed TOP-003 require the Generator Operator to provide Real-time data as directed by the TOP.

Rationale for R5:

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

Rationale for Exclusion in R5:

The Transmission Operator and Transmission Planner only need to review tap settings, available fixed tap ranges, impedance data and the +/- voltage range with step-change in % for load-tap changing transformers on main generator step-up unit transformers which connect dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition to their transmission system. The dispersed power producing resources individual generator transformers are not intended, designed or installed to improve voltage performance at the point of interconnection. In addition, the dispersed power producing resources individual generator transformers have traditionally been excluded from Requirement R4 and R5 of VAR- 002-2b (similar requirements are R5 and R6 for VAR-002-3), as they are not used to improve voltage performance at the point of interconnection.

Rationale for R6:

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

Exhibit C

Proposed WECC Regional Reliability Standard VAR-501-WECC-3.1 (Power System Stabilizer)

Exhibit C-1

Proposed WECC Regional Reliability Standard VAR-501-WECC-3.1 Clean

A. Introduction

1. **Title:** Power System Stabilizer (PSS)
2. **Number:** VAR-501-WECC-3.1
3. **Purpose:** To ensure the Western Interconnection is operated in a coordinated manner under normal and abnormal conditions by establishing the performance criteria for WECC power system stabilizers.
4. **Applicability:**

   4.1 Generator Operator

   4.2 Generator Owner
5. **Facilities:** This standard applies to synchronous generators, connected to the Bulk Electric System, that meet the definition of Commercial Operation.
6. **Effective Date:** The first day of the first quarter following regulatory approval, except for Requirement R3.

   For units placed in first-time service after regulatory approval, Requirement R3 is effective the first day of the first quarter following final regulatory approval.

   For units placed in service prior to final regulatory approval, Requirement R3 is effective the first day of the first quarter that is five years after regulatory approval.

B. Requirements and Measures

R1. Each Generator Owner shall provide to its Transmission Operator, the Generator Owner's written Operating Procedure or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days of any of the following events: *[Violation Risk Factor: Low] [Time Horizon: Planning Horizon]*

- The effective date of this standard;
- The PSS's Commercial Operation date; or
- Any changes to the PSS operating specifications.

M1. Each Generator Owner will have documented evidence that it provided to its Transmission Operator, within the time allotted as described in the procedures required under Requirement R1, written Operating Procedures or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the AVR.

For auditing purposes, because Requirement R1 conditions are intended to be unchanged unless the Transmission Operator is otherwise notified, the Generator Owner only needs to provide the documentation to the Transmission Operator one time, or whenever the operating specifications change.

For auditing purposes, if a PSS is in service but is not providing an active signal to the AVR as described in Requirement R1, the disabled period does not count against the Requirement R2 mandate to be in service except as otherwise allowed.

R2. Each Generator Operator shall have its PSS in service while synchronized, except during any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operating Assessment]*

- Component failure
- Testing of a Bulk Electric System Element affecting or affected by the PSS
- Maintenance
- As agreed upon by the Generator Operator and the Transmission Operator

A PSS that is out of service for less than 30 minutes does not create a violation of this Requirement, regardless of cause.

M2. Each Generator Operator will have documentation of each claimed exception specified in Requirement R2. Documentation may include, but is not limited to:

- A written explanation covering the bulleted exception that describes the circumstances of the exception as allowed in Requirement R2.
- Documented evidence that the Generator Operator and the Transmission Operator agreed the PSS would not be operating during a specified set of circumstances, where the exception is claimed under the last bullet of Requirement R2.

For auditing purposes, the presumption is that the PSS was in service unless otherwise exempted in Requirement R2. Evidence need only be provided to prove the circumstances during which the PSS was not in service for periods in excess of 30 minutes.

R3. Each Generator Owner shall tune its PSS to meet the following inter-area mode criteria, except as specified in Requirement R3, Part 3.5 below: *[Violation Risk Factor: Medium] [Time Horizon: Operating Assessment]*

3.1. PSS shall be set to provide the measured, simulated, or calculated compensated Vt/Vref frequency response of the excitation system and synchronous machine such that the phase angle will not exceed ± 30 degrees through the frequency range from 0.2 Hertz to the lesser of 1.0 Hertz or the highest frequency at which the phase of the Vt/Vref frequency response does not exceed 90 degrees.

3.2. PSS output limits shall be set to provide at least ±5% of the synchronous machine's nominal terminal voltage.

3.3. PSS gain shall be set to between 1/3 and 1/2 of maximum practical gain.

3.4. PSS washout time constant shall be no greater than 30 seconds.

3.5. Units that have an excitation system or PSS that is incapable of meeting the tuning requirements of Requirement R3 are exempt from Requirement R3 until the voltage regulator is either replaced or retrofitted such that the PSS becomes capable of meeting the tuning requirements.

M3. Each Generator Owner will have documented evidence that its PSS was tuned to meet the specifications of Requirement R3.

If the exception under Requirement R3, Part 3.5, is claimed, the Generator Owner will have documented evidence describing: 1) the conditions that render the PSS incapable of meeting the tuning requirements, and 2) the date the voltage regulator was last replaced or retrofitted.

R4. Each Generator Owner shall install and complete start-up testing of a PSS on its generator within 180 days of either of the following events: *[Violation Risk Factor: Medium] [Time Horizon: Operational Assessment]*

- The Generator Owner connects a generator to the BES, after achieving Commercial Operation, and after the Effective Date of this standard.
- The Generator Owner replaces the voltage regulator on its existing excitation system, after achieving Commercial Operation for its generator that is connected to the BES, and after the Effective Date of this standard.

M4. Each Generator Owner will have evidence that it installed and completed start-up testing of a PSS on its generator within 180 days of either of the conditions described in Requirement R4, and when those conditions occur after the Effective Date of this standard.

For auditing purposes of Requirement R4, bullet one only applies to equipment on its initial (first energization) connection to the BES.

R5. Each Generator Owner shall repair or replace a PSS within 24 months of that PSS becoming incapable of meeting the tuning specifications stated in Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Operational Assessment]*

M5. Each Generator Owner will have evidence that it repaired or replaced its PSS within 24 months of that PSS becoming incapable of meeting the tuning specifications of Requirement R3. Evidence may include, but is not limited to, documentation of the date the PSS became incapable of meeting the Requirement R3 tuning specifications, and the date the PSS was returned to service, demonstrating that the span of time between the two events was less than 24 months.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2 Compliance Monitoring and Assessment Processes

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

1.3 Evidence Retention

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

Each Generator Operator shall keep evidence for all Requirements of the document for a period of three years plus calendar current.

1.4 Additional Compliance Information

None

D. Regional Differences

None

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Planning Horizon	Low	NA	NA	NA	The Generator Owner failed to provide its PSS operating specifications to the Transmission Operator as required in Requirement R1.
R2	Operations Assessment	Medium	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 30 minutes but less than 60 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 60 minutes but less than 120 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 120 minutes but less than 180 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 180 minutes.
R3	Operations Assessment	Medium	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, two times or fewer during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, three times during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, four times during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, five times or more during the audit period.

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operational Assessment	Medium	NA	NA	NA	The Generator Owner failed to install on its generator a PSS, as required in Requirement R4.
R5	Operational Assessment	Medium	NA	NA	NA	The Generator Owner failed to repair or replace a non-operational PSS as required in Requirement R5.

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002b-1	
1	October 28, 2008	Adopted by NERC Board of Trustees	
1	April 21, 2011	FERC Order issued approving VAR-501-WECC-1 (FERC approval effective June 27, 2011; Effective Date July 1, 2011)	
2	November 13, 2014	Adopted by NERC Board of Trustees	
2	March 3, 2015	FERC letter order approved VAR-501-WECC-2	
3	February 9, 2017	Adopted by NERC Board of Trustees	
3	April 28, 2017	FERC letter order approved VAR-501-WECC-3	
3.1	August 10, 2017	Adopted by the NERC Board of Trustees	Errata

Guideline and Technical Basis

PSS systems are used to minimize real power oscillations by rapidly adjusting the field of the generator to dampen the low-frequency oscillations.

It is necessary for large numbers of PSS devices to be in operation in the Western Interconnection to provide the required system damping while still allowing for some of these units to be out of service whenever necessary.

Mandate to Install a PSS

Nothing in this Regional Reliability Standard (RSS) should be construed to require installation of a PSS *solely because* a PSS is not currently installed as of the Effective Date of this RRS. Rather, installation is only mandated on the occurrence of either of the triggering events described in Requirement R4, Bullet 1 or Bullet 2, after the Effective Date of the RRS.

It should be noted that a PSS is neither Transmission nor generation.

Requirement R1

Requirement R1 addresses normal operating conditions.

Requirement R1 recognizes that PSS systems have varying states, such as on, off, active, and non-active. As long as the PSS is operating in accordance with the documentation provided to the Transmission Operator, this is not considered a status change for purposes of this standard.

This Requirement eliminates the requirement to count hours as required in the previous version of this standard while also allowing the Generator Owner to create a unit-specific operating plan.

The intent of Requirement R1 is to provide the Transmission Operator, the PSS operating zone in which the PSS is "active" providing damping to the power system. Some PSS may be programmed to become "active" at a specified megawatt loading level and above while others may be programmed to be "active" in a particular band of megawatt loading levels and are "non-active" only when passing through the "rough zone" or some other band. A "rough zone" is a megawatt loading band in which the generator-turbine system could contribute to system instability.

Requirement R2

This Requirement only applies when the PSS is out of service for a period greater than 30 minutes.

Unlike Requirement R1, Requirement R2 addresses exceptions to normal operation.

The intent of Requirement R2 is to remove the previous requirement to log hours for PSS in service. In this standard's previous version, the logged hours were totaled quarterly to meet the

98% in-service requirement. Instead of documenting the number of hours excluded, this Requirement simplifies the process by allowing the Generator Operator to communicate to the Transmission Operator the circumstances that render the PSS unavailable to the Transmission Operator (such as component failure, maintenance, and testing).

Requirement R3

Nothing in this RSS should be construed to mandate the design criteria for the *equipment* used to produce the tuning output of the PSS. Rather, Requirement R3 is intended to address the design criteria for the *tuning output* of the PSS.

Unlike the language in Requirement R5 that looks *backward* to address units that were once operating but are no longer capable of operating, Requirement R3 looks *forward*, requiring that units be tuned to the specified parameters.

The PSS transfer function should compensate the phase characteristics of the generator, exciter, and power (GEP) system transfer function so the compensated transfer function ((PSS(s) * GEP(s)) has a phase characteristic of ± 30 degrees in the frequency range.

The GEP(s) transfer function is a theoretical transfer function and its phase characteristic cannot be directly measured during field tests (only via simulation). Thus, the Requirement recognizes the practical approach of measuring the frequency response between voltage reference set point and terminal voltage (Et/Vref) and using the phase characteristic of such frequency response as being the phase characteristic of GEP(s). The phase characteristic of Et/Vref is a better approximation to the phase characteristic of GEP(s) when the frequency response Et/Vref is obtained with the generator synchronized to the grid at its minimum stable power output.

In an effort to allow for reasonable wash-out time constants, the Requirement specifies 0.2 Hz as the applicable threshold. The 0.2 Hz threshold more closely aligns with the observed oscillation frequencies.

A properly tuned PSS should provide positive damping to the local mode of oscillation, which typically has a frequency higher than 1.0 Hz.

This Requirement modifies the requirement associated with the adjustment of the PSS gain. The standard no longer defines the PSS gain in terms of gain margin but instead requires the final PSS gain to be between 1/3 (10 dB) and 1/2 (6 dB) of the maximum practical gain that could be achieved during PSS commissioning. The maximum practical gain might be associated with the excessive noise or raised higher-frequency oscillations in the closed loop response (exciter mode) or any other form if there is inadequate closed-loop performance, as determined during PSS commissioning. It is now part of Measure M3 to show the field test results that led to the determination of the maximum practical gain.

Requirement R4

Requirement R4 requires a Generator Owner to install a PSS on new applicable units or when excitation systems are replaced or retrofitted on existing applicable units. This Requirement applies to new excitation systems and not to existing systems that do not have PSS. The Requirement also allows a reasonable amount of time for the commissioning of new PSS.

Requirement R5

Unlike the language in Requirement R3 that looks *forward* to ensure that a unit is tuned, Requirement R5 looks *backward.* Specifically, the language in Requirement R5, “becoming incapable,” indicates the unit was previously capable of meeting the tuning requirements in Requirement R3, but is no longer capable. Restated, Requirement R5 addresses units that were previously working but are now no longer working.

The intent of Requirement R5 is to remove the “tiered” approach to PSS repair/replacement following a failure. A simple, streamlined approach to allow the Generator Owner sufficient time to repair or replace a broken PSS has been written. Consideration has been given for the need to procure parts or new equipment, schedule an equipment/unit outage, and install and test the repaired or replaced PSS. It is recognized that in some instances, it may require (1) replacement of an AVR, and (2) the existence of a PSS, or both the AVR and the PSS may need to be replaced to achieve a functioning system.

The 24-month time frame is sufficient to return a functional, operating PSS to service.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard VAR-501-WECC-3 — Power System Stabilizer

United States

Standard	Requirement	Enforcement Date	Inactive Date
VAR-501-WECC-3	TBD	TBD	

Exhibit C-2

Proposed WECC Regional Reliability Standard VAR-501-WECC-3.1 Redline

A. Introduction

1. **Title:** Power System Stabilizer (PSS)
2. **Number:** VAR-501-WECC-3.1
3. **Purpose:** To ensure the Western Interconnection is operated in a coordinated manner under normal and abnormal conditions by establishing the performance criteria for WECC power system stabilizers.
4. **Applicability:**

   4.1 Generator Operator

   4.2 Generator Owner
5. **Facilities:** This standard applies to synchronous generators, connected to the Bulk Electric System, that meet the definition of Commercial Operation.
6. **Effective Date:** The first day of the first quarter following regulatory approval, except for Requirement R3.

   For units placed in first-time service after regulatory approval, Requirement R3 is effective the first day of the first quarter following final regulatory approval.

   For units placed in service prior to final regulatory approval, Requirement R3 is effective the first day of the first quarter that is five years after regulatory approval.

B. Requirements and Measures

R1. Each Generator Owner shall provide to its Transmission Operator, the Generator Owner's written Operating Procedure or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days of any of the following events: *[Violation Risk Factor: Low] [Time Horizon: Planning Horizon]*

- The effective date of this standard;
- The PSS's Commercial Operation date; or
- Any changes to the PSS operating specifications.

M1. Each Generator Owner will have documented evidence that it provided to its Transmission Operator, within the time allotted as described in the procedures required under Requirement R1, written Operating Procedures or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the AVR.

For auditing purposes, because Requirement R1 conditions are intended to be unchanged unless the Transmission Operator is otherwise notified, the Generator Owner only needs to provide the documentation to the Transmission Operator one time, or whenever the operating specifications change.

For auditing purposes, if a PSS is in service but is not providing an active signal to the AVR as described in Requirement R1, the disabled period does not count against the Requirement R2 mandate to be in service except as otherwise allowed.

R2. Each Generator Operator shall have its PSS in service while synchronized, except during any of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operating Assessment]*

- Component failure
- Testing of a Bulk Electric System Element affecting or affected by the PSS
- Maintenance
- As agreed upon by the Generator Operator and the Transmission Operator

A PSS that is out of service for less than 30 minutes does not create a violation of this Requirement, regardless of cause.

M2. Each Generator Operator will have documentation of each claimed exception specified in Requirement R2. Documentation may include, but is not limited to:

- A written explanation covering the bulleted exception that describes the circumstances of the exception as allowed in Requirement R2.
- Documented evidence that the Generator Operator and the Transmission Operator agreed the PSS would not be operating during a specified set of circumstances, where the exception is claimed under the last bullet of Requirement R2.

For auditing purposes, the presumption is that the PSS was in service unless otherwise exempted in Requirement R2. Evidence need only be provided to prove the circumstances during which the PSS was not in service for periods in excess of 30 minutes.

R3. Each Generator Owner shall tune its PSS to meet the following inter-area mode criteria, except as specified in Requirement R3, Part 3.5 below: *[Violation Risk Factor: Medium] [Time Horizon: Operating Assessment]*

3.1. PSS shall be set to provide the measured, simulated, or calculated compensated Vt/Vref frequency response of the excitation system and synchronous machine such that the phase angle will not exceed ± 30 degrees through the frequency range from 0.2 Hertz to the lesser of 1.0 Hertz or the highest frequency at which the phase of the Vt/Vref frequency response does not exceed 90 degrees.

3.2. PSS output limits shall be set to provide at least ±5% of the synchronous machine's nominal terminal voltage.

3.3. PSS gain shall be set to between 1/3 and 1/2 of maximum practical gain.

3.4. PSS washout time constant shall be no greater than 30 seconds.

3.5. Units that have an excitation system or PSS that is incapable of meeting the tuning requirements of Requirement R3 are exempt from Requirement R3 until the voltage regulator is either replaced or retrofitted such that the PSS becomes capable of meeting the tuning requirements.

M3. Each Generator Owner will have documented evidence that its PSS was tuned to meet the specifications of Requirement R3.

If the exception under Requirement R3, Part 3.5, is claimed, the Generator Owner will have documented evidence describing: 1) the conditions that render the PSS incapable of meeting the tuning requirements, and 2) the date the voltage regulator was last replaced or retrofitted.

R4. Each Generator Owner shall install and complete start-up testing of a PSS on its generator within 180 days of either of the following events: *[Violation Risk Factor: Medium] [Time Horizon: Operational Assessment]*

- The Generator Owner connects a generator to the BES, after achieving Commercial Operation, and after the Effective Date of this standard.
- The Generator Owner replaces the voltage regulator on its existing excitation system, after achieving Commercial Operation for its generator that is connected to the BES, and after the Effective Date of this standard.

M4. Each Generator Owner will have evidence that it installed and completed start-up testing of a PSS on its generator within 180 days of either of the conditions described in Requirement R4, and when those conditions occur after the Effective Date of this standard.

For auditing purposes of Requirement R4, bullet one only applies to equipment on its initial (first energization) connection to the BES.

R5. Each Generator Owner shall repair or replace a PSS within 24 months of that PSS becoming incapable of meeting the tuning specifications stated in Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Operational Assessment]*

M5. Each Generator Owner will have evidence that it repaired or replaced its PSS within 24 months of that PSS becoming incapable of meeting the tuning specifications of Requirement R3. Evidence may include, but is not limited to, documentation of the date the PSS became incapable of meeting the Requirement R3 tuning specifications, and the date the PSS was returned to service, demonstrating that the span of time between the two events was less than 24 months.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2 Compliance Monitoring and Assessment Processes

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

1.3 Evidence Retention

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

Each Generator Operator shall keep evidence for all Requirements of the document for a period of three years plus calendar current.

1.4 Additional Compliance Information

None

D. Regional Differences

None

Table of Compliance Elements

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Planning Horizon	Low	NA	NA	NA	The Generator Owner failed to provide its PSS operating specifications to the Transmission ~~Planner~~Operator as required in Requirement R1.
R2	Operations Assessment	Medium	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 30 minutes but less than 60 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 60 minutes but less than 120 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 120 minutes but less than 180 minutes.	Each Generator Operator not having its PSS in service while synchronized in accordance with Requirement R2, for more than 180 minutes.
R3	Operations Assessment	Medium	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, two times or fewer during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, three times during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, four times during the audit period.	The Generator Owner's PSS failed to meet any of the required performances in Requirement R3, five times or more during the audit period.

R	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operational Assessment	Medium	NA	NA	NA	The Generator Owner failed to install on its generator a PSS, as required in Requirement R4.
R5	Operational Assessment	Medium	NA	NA	NA	The Generator Owner failed to repair or replace a non-operational PSS as required in Requirement R5.

Version History

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for VAR-STD-002b-1	
1	October 28, 2008	Adopted by NERC Board of Trustees	
1	April 21, 2011	FERC Order issued approving VAR-501-WECC-1 (FERC approval effective June 27, 2011; Effective Date July 1, 2011)	
2	November 13, 2014	Adopted by NERC Board of Trustees	
2	March 3, 2015	FERC letter order approved VAR-501-WECC-2	
3	~~TBD~~February 9, 2017	~~TBD~~Adopted by NERC Board of Trustees	
3	April 28, 2017	FERC letter order approved VAR-501-WECC-3	
3.1	August 10, 2017	Adopted by the NERC Board of Trustees	Errata

Guideline and Technical Basis

PSS systems are used to minimize real power oscillations by rapidly adjusting the field of the generator to dampen the low-frequency oscillations.

It is necessary for large numbers of PSS devices to be in operation in the Western Interconnection to provide the required system damping while still allowing for some of these units to be out of service whenever necessary.

Mandate to Install a PSS

Nothing in this Regional Reliability Standard (RSS) should be construed to require installation of a PSS *solely because* a PSS is not currently installed as of the Effective Date of this RRS. Rather, installation is only mandated on the occurrence of either of the triggering events described in Requirement R4, Bullet 1 or Bullet 2, after the Effective Date of the RRS.

It should be noted that a PSS is neither Transmission nor generation.

Requirement R1

Requirement R1 addresses normal operating conditions.

Requirement R1 recognizes that PSS systems have varying states, such as on, off, active, and non-active. As long as the PSS is operating in accordance with the documentation provided to the Transmission ~~Planner~~Operator, this is not considered a status change for purposes of this standard.

This Requirement eliminates the requirement to count hours as required in the previous version of this standard while also allowing the Generator Owner to create a unit-specific operating plan.

The intent of Requirement R1 is to provide the Transmission ~~Planner~~Operator, the PSS operating zone in which the PSS is “active” providing damping to the power system. Some PSS may be programmed to become “active” at a specified megawatt loading level and above while others may be programmed to be “active” in a particular band of megawatt loading levels and are “non-active” only when passing through the “rough zone” or some other band. A “rough zone” is a megawatt loading band in which the generator-turbine system could contribute to system instability.

Requirement R2

This Requirement only applies when the PSS is out of service for a period greater than 30 minutes.

Unlike Requirement R1, Requirement R2 addresses exceptions to normal operation.

The intent of Requirement R2 is to remove the previous requirement to log hours for PSS in service. In this standard's previous version, the logged hours were totaled quarterly to meet the 98% in-service requirement. Instead of documenting the number of hours excluded, this Requirement simplifies the process by allowing the Generator Operator to communicate to the Transmission Operator the circumstances that render the PSS unavailable to the Transmission Operator (such as component failure, maintenance, and testing).

Requirement R3

Nothing in this RSS should be construed to mandate the design criteria for the *equipment* used to produce the tuning output of the PSS. Rather, Requirement R3 is intended to address the design criteria for the *tuning output* of the PSS.

Unlike the language in Requirement R5 that looks *backward* to address units that were once operating but are no longer capable of operating, Requirement R3 looks *forward*, requiring that units be tuned to the specified parameters.

The PSS transfer function should compensate the phase characteristics of the generator, exciter, and power (GEP) system transfer function so the compensated transfer function ((PSS(s) * GEP(s)) has a phase characteristic of ± 30 degrees in the frequency range.

The GEP(s) transfer function is a theoretical transfer function and its phase characteristic cannot be directly measured during field tests (only via simulation). Thus, the Requirement recognizes the practical approach of measuring the frequency response between voltage reference set point and terminal voltage (Et/Vref) and using the phase characteristic of such frequency response as being the phase characteristic of GEP(s). The phase characteristic of Et/Vref is a better approximation to the phase characteristic of GEP(s) when the frequency response Et/Vref is obtained with the generator synchronized to the grid at its minimum stable power output.

In an effort to allow for reasonable wash-out time constants, the Requirement specifies 0.2 Hz as the applicable threshold. The 0.2 Hz threshold more closely aligns with the observed oscillation frequencies.

A properly tuned PSS should provide positive damping to the local mode of oscillation, which typically has a frequency higher than 1.0 Hz.

This Requirement modifies the requirement associated with the adjustment of the PSS gain. The standard no longer defines the PSS gain in terms of gain margin but instead requires the final PSS gain to be between 1/3 (10 dB) and 1/2 (6 dB) of the maximum practical gain that could be achieved during PSS commissioning. The maximum practical gain might be associated with the excessive noise or raised higher-frequency oscillations in the closed loop response (exciter mode) or any other form if there is inadequate closed-loop performance, as determined during PSS commissioning. It is now part of Measure M3 to show the field test results that led to the determination of the maximum practical gain.

Requirement R4

Requirement R4 requires a Generator Owner to install a PSS on new applicable units or when excitation systems are replaced or retrofitted on existing applicable units. This Requirement applies to new excitation systems and not to existing systems that do not have PSS. The Requirement also allows a reasonable amount of time for the commissioning of new PSS.

Requirement R5

Unlike the language in Requirement R3 that looks *forward* to ensure that a unit is tuned, Requirement R5 looks *backward.* Specifically, the language in Requirement R5, "becoming incapable," indicates the unit was previously capable of meeting the tuning requirements in Requirement R3, but is no longer capable. Restated, Requirement R5 addresses units that were previously working but are now no longer working.

The intent of Requirement R5 is to remove the "tiered" approach to PSS repair/replacement following a failure. A simple, streamlined approach to allow the Generator Owner sufficient time to repair or replace a broken PSS has been written. Consideration has been given for the need to procure parts or new equipment, schedule an equipment/unit outage, and install and test the repaired or replaced PSS. It is recognized that in some instances, it may require (1) replacement of an AVR, and (2) the existence of a PSS, or both the AVR and the PSS may need to be replaced to achieve a functioning system.

The 24-month time frame is sufficient to return a functional, operating PSS to service.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard VAR-501-WECC-3 — Power System Stabilizer

United States

Standard	Requirement	Enforcement Date	Inactive Date
VAR-501-WECC-3	TBD	TBD	