UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. RD14-___-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS VAR-001-4 AND VAR-002-3 AND THE RETIREMENT OF RELIABILITY STANDARDS VAR-001-3 AND VAR-002-2b

Gerald W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Shamai Elstein
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, DC 20005
(202) 400-3000
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
shamai.elstein@nerc.net

Counsel for the North American Electric Reliability Corporation

June 9, 2014

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RD14-___-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARDS VAR-001-4 AND VAR-002-3 AND THE RETIREMENT OF RELIABILITY STANDARDS VAR-001-3 AND VAR-002-2b

Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the Commission's Regulations,[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standards VAR-001-4 (Voltage and Reactive Control) and VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) for Commission approval.[4] NERC requests that the Commission approve proposed Reliability Standards VAR-001-4 and VAR-002-3 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[5] NERC also requests approval of (i) the associated Implementation Plan, (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), and (iii) the retirement of currently effective Reliability Standards VAR-001-3 and VAR-002-2b, as detailed in this Petition.

---

1 16 U.S.C. § 824o(d)(1) (2012).

2 18 C.F.R. § 39.5 (2013).

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, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009) ("ERO Certification Order").

4 The NERC Board of Trustees approved proposed Reliability Standards VAR-001-4 on February 6, 2014 and VAR-002-3 on May 7, 2014.

5 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf.

As required by Section 39.5(a)[6] of the Commission's Regulations, this Petition presents the technical basis and purpose of proposed Reliability Standards VAR-001-4 and VAR-002-3, a summary of the development history, and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672.[7] This Petition is organized as follows: First, the Petition presents an executive summary of the proposed Reliability Standards. Next, the Petition provides background on the regulatory structure governing the Reliability Standards approval process, as well as information on the existing Reliability Standards that proposed VAR-001-4 and VAR-002-3 Reliability Standards will replace. The Petition then discusses the proposed Reliability Standards in detail, including how they satisfy the governing statutory criteria and the Commission's directives associated with these Reliability Standards. Finally, we provide the requested effective date for the proposed Reliability Standards.

The following documents are attached as exhibits to this Petition: (a) the proposed Reliability Standards (Exhibit A, with VAR-001-4 as Exhibit A-1 and VAR-002-3 as Exhibit A-2), (b) the proposed Implementation Plan for the proposed Reliability Standards (Exhibit B), (c) a discussion of how the proposed Reliability Standards satisfy the Order No. 672 criteria (Exhibit C), (d) mapping documents showing how the proposed Reliability Standards compare to the corresponding existing Reliability Standards (Exhibit D, with VAR-001-4 compared against VAR-001-3 as Exhibit D-1 and VAR-002-3 compared against VAR-002-2b as Exhibit D-2), (e) an analysis of the VRFs and VSLs for the proposed Reliability Standards (Exhibit E), (f) a

---

6 18 C.F.R. § 39.5(a) (2013).

7 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at PP 262, 321–37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

summary of the development history and record of development for the proposed Reliability Standards (Exhibit F), and (g) the standard drafting team roster (Exhibit G).

I. EXECUTIVE SUMMARY

The Voltage and Reactive ("VAR") group of Reliability Standards, which consists of two continent-wide Reliability Standards, VAR-001-3 and VAR-002-2b,[8] is designed to maintain voltage stability on the Bulk-Power System, protect transmission, generation, distribution, and customer equipment, and support the reliable operation of the Bulk-Power System. Voltage stability is the ability of a power system to maintain acceptable voltage levels throughout the system under normal operating conditions and following a disturbance. Failure to maintain acceptable voltage levels (*i.e.*, voltage levels become too high or too low) may cause violations of System Operating Limits ("SOLs") and Interconnection Reliability Operating Limits ("IROLs"), result in damage to Bulk-Power System equipment, and thereby threaten the reliable operation of the Bulk-Power System. The primary factor in maintaining voltage stability is having the appropriate amount of Reactive Power on the system.[9] Proposed Reliability Standards VAR-001-4 and VAR-002-3 are intended to replace and improve upon Reliability Standards VAR-001-3 and VAR-002-2b, respectively, to ensure that the Bulk-Power System operates at acceptable voltage levels and that sufficient Reactive Power is available to maintain voltage stability.

---

[8] The VAR group of Reliability Standards also includes two regional Reliability Standards, VAR-002-WECC-1 and VAR-501-WECC-1. NERC is not proposing any modifications to these regional Reliability Standards. Additionally, VAR-001-3 includes a regional variance developed by the Western Electricity Coordinating Council ("WECC") applicable to Generator Operators located in the WECC region. NERC has not substantively modified the WECC regional variance and it will be carried forward as part of VAR-001-4. Accordingly, this Petition does not discuss the two regional Reliability Standards or the regional variance.

[9] Reactive Power is the portion of electricity that establishes and sustains the electric and magnetic fields of Bulk-Power System equipment and supports voltage stability.

In general, proposed Reliability Standard VAR-001-4 sets forth the requirements applicable to Transmission Operators for scheduling, monitoring, and controlling Reactive Power resources in the Real-time Operations, Same-day Operations, and Operational Planning time horizons to regulate voltage and Reactive Power flows for the reliable operation of the Bulk-Power System. Proposed Reliability Standard VAR-002-3 sets forth the requirements applicable to Generator Operators and Generator Owners for providing the necessary reactive support and voltage control necessary to maintain reliable operations. Generators are the largest and most reliable Reactive Power resource and play an integral role in maintaining voltage stability on the Bulk-Power System. Collectively, the proposed Reliability Standards are designed to prevent voltage instability and voltage collapse on the Bulk-Power System.

As described further below, proposed Reliability Standard VAR-001-4 requires each Transmission Operator to:

- Specify a system-wide voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within SOLs and IROLs, and to provide the voltage schedule to its Reliability Coordinator and adjacent Transmission Operators upon request (Requirement R1);

- Schedule sufficient reactive resources to regulate voltage levels (Requirement R2);

- Operate or direct the operation of devices to regulate transmission voltage and reactive flows (Requirement R3);

- Develop a set of criteria to exempt generators from certain requirements under Reliability Standard VAR-002-3 related to voltage or Reactive Power schedules, automatic voltage regulations, and notification (Requirement R4);

- Specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) for generators at either the high or low voltage side of the generator step-up transformer, provide the schedule to the associated Generator Operator, direct the Generator Operator to comply with that schedule in automatic voltage control mode, provide the Generator Operator the notification requirements for deviating from the schedule, and, if requested, provide the Generator Operator the criteria used to develop the schedule (Requirement R5); and

- Communicate step-up transformer tap changes, the time frame for completion, and the justification for these changes to Generator Owners (Requirement R6).

Proposed Reliability Standard VAR-002-3 requires each Generator Operator to:

- Operate each of its generators connected to the interconnected transmission system in automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, unless the Generator Operator (1) is exempted pursuant to the criteria developed under VAR-001-4, Requirement R4, or (2) makes certain notifications to the Transmission Operator specifying the reasons it cannot so operate (Requirement R1);

- Maintain the Transmission Operator's generator voltage or Reactive Power schedule, unless the Generator Operator (1) is exempted pursuant to the criteria developed under VAR-001-4, Requirement R4, or (2) complies with the notification requirements for deviations as established by the Transmission Owner pursuant to VAR-001-4, Requirement R5 (Requirement R2);[10]

- Notify the Transmission Operator of a change in status of its voltage controlling device within 30 minutes, unless the status is restored within that time period (Requirement R3); and

- Notify the Transmission Operator of a change in reactive capability due to factors other than those described in VAR-002-3, Requirement R3 within 30 minutes unless the capability has been restored during that time period (Requirement R4).

Proposed Reliability Standard VAR-002-3 also requires each Generator Owner to:

- Provide information on its step-up transformers and auxiliary transformers within 30 days of a request from the Transmission Operator or Transmission Planner (Requirement R5); and

- Comply with the Transmission Operator's step-up transformer tap change directives unless compliance would violate safety, an equipment rating, or applicable laws, rules or regulations (Requirement R6).

---

[10] VAR-002-3, Requirement R2 also provides that: (1) when a generator's AVR is out of service or the generator does not have AVR, the Generator Operator shall use an alternative method to control the generator's Reactive Power output to meet the schedule; (2) when instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met; and (3) if the Generator Operator does not monitor voltage at the location specified in its voltage schedule, it shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

The proposed Reliability Standards were developed to address outstanding Commission directives from Order Nos. 693[11] and 724[12] and build upon the previous versions of the Reliability Standards to improve their quality and content.[13] In addition to addressing certain Commission directives, the proposed Reliability Standards streamline language for increased clarity, omit requirements duplicative with or otherwise unnecessary when compared to existing Reliability Standards, and remove requirements that provide little to no reliability benefit. As discussed further below, Reliability Standard VAR-001-4 improves upon the prior version of the standard as follows:

- Requirements that are duplicative of other currently enforceable and pending Reliability Standards are removed.

- Requirement R1 improves reliability by requiring Transmission Operators to (1) define system voltage schedules, which may be a range or a target value with an associated tolerance band, to help ensure the Bulk-Power System operates within operating limits, and (2) coordinate with adjacent Transmission Operators and Reliability Coordinators regarding those system voltage schedules.

- Requirement R2 consolidates Requirements R2 and R9 of VAR-001-3 to clarify the Transmission Operator's responsibility to schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions.[14]

- Requirement R3 consolidates Requirements R7 and R8 of VAR-001-3 to clarify the Transmission Operator's responsibility to provide the necessary voltage support (*i.e.*, "operate or direct the Real-time operation of devices"[15]) to help maintain voltage stability.

- Requirement R4 continues to provide Transmission Operators the flexibility to exempt generators from certain compliance obligations, but clarifies the obligations from which

---

[11] *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[12] *Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, Order No. 724, 127 FERC ¶ 61,158 (2009).

[13] Exhibits D-1 and D-2 to this Petition provide mapping documents comparing the existing VAR-001-3 and VAR-002-2b Reliability Standards to the proposed VAR-001-4 and VAR-002-3 Reliability Standards.

[14] A Contingency is defined in the NERC Glossary as "the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element."

[15] VAR-001-4, Requirement R3.

generators may be exempt. Requirement R4 also eliminates the need for Transmission Operators to maintain a list of all generators that have been granted an exemption as such a requirement provides little to no reliability benefit.

- Requirement R5 creates a more transparent information-sharing process between Transmission Operators and Generator Operators about voltage or Reactive Power schedules and notification requirements for deviating from such schedules.

- Requirement R5 also addresses the Commission's Order No. 693 directive to consider a time frame associated with an "incident" of non-compliance with VAR-002,[16] as well as the Order No. 724 directive to develop and implement technically sound voltage schedules.

Further, in proposed Reliability Standard VAR-002-3:

- Requirements R1 and R2 carry forward the obligations that Generator Operators operate in automatic voltage control mode and follow the voltage or Reactive Power schedule provided by the Transmission Operator but provide Generator Operators increased flexibility to deviate from voltage or Reactive Power schedules and operational modes where system-specific circumstances or events may require these deviations to protect reliability and prevent equipment damage.

- Requirements R3 and R4 remove unnecessary and overly burdensome communication requirements that provide little to no reliability benefit. Eliminating these notification requirements will enable Transmission Operators to focus resources on improving system monitoring and responding to voltage issues as they may arise in Real-time.

- Requirements R5 and R6 improve clarity by removing extraneous language (Requirement R5) and adopting consistent language throughout the requirement (Requirement R6), which will help responsible entities understand and more effectively apply these requirements.

For the reasons discussed herein, NERC respectfully requests that the Commission approve proposed Reliability Standards VAR-001-4 and VAR-002-3 as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

[16] As further discussed in Section IV.C, this Commission directive was issued in reference to Reliability Standard VAR-002. However, the standard drafting team determined that this directive is more appropriately addressed in VAR-001-4, Requirement R5.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing should be addressed to the following:[17]

Charles A. Berardesco*
Senior Vice President and General Counsel
Holly A. Hawkins*
Assistant General Counsel
Shamai Elstein*
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, DC 20005
(202) 400-3000
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
shamai.elstein@nerc.net

Valerie Agnew*
Director of Standards Development
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
valerie.agnew@nerc.net

III. BACKGROUND

A. Regulatory Framework

In FPA section 215,[18] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the nation's Bulk-Power System, and certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval.[19] All users, owners, and operators of the Bulk-Power System in the United States are subject to Commission-approved Reliability Standards.[20] The ERO must obtain Commission approval of each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, as well as modifications to the Reliability

---

17 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, to allow the inclusion of more than two persons on the service list in this proceeding.

18 16 U.S.C. § 824o.

19 The Commission certified NERC as the ERO. *See* Order No. 672, *order on reh'g*, Order No. 672-A; ERO Certification Order, *supra* note 3.

20 16 U.S.C. § 824o(b)(1).

Standards,[21] and the Commission may order the ERO to submit new or modified Reliability Standards.[22]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission gives due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.[23]

B. NERC Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 of the NERC Rules of Procedure and the NERC Standard Processes Manual.[24] The Commission has found that the NERC Rules of Procedure provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards, and thus satisfy certain of the criteria for approving Reliability Standards.[25] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers all stakeholder comments and requires a vote by stakeholders as well as the NERC Board of Trustees to approve a Reliability Standard before NERC will submit the

---

[21] 18 C.F.R. § 39.5(a).

[22] 16 U.S.C. § 824o(d)(5).

[23] 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

[24] Rules of Procedure of the North American Electric Reliability Corporation, § 300 ("NERC Rules of Procedure"), *available at* http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx; Standard Processes Manual, v.3 (June 26, 2013), *available at* http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[25] ERO Certification Order at P 250.

Reliability Standard for Commission approval. NERC developed proposed Reliability Standards VAR-001-4 and VAR-002-3 in an open and fair manner and in accordance with this process.[26]

C. The Existing VAR Reliability Standards

1. Reliability Standard VAR-001-3

Currently enforceable Reliability Standard VAR-001-3 requires Transmission Operators to monitor, control and maintain voltage levels, reactive flows and reactive resources within certain limits in Real-time to protect equipment and the reliable operation of the Interconnection.[27] Under the existing requirements,[28] each Transmission Operator is required to:

- Individually and jointly with other Transmission Operators ensure that formal policies and procedures are developed, maintained and implemented for monitoring and controlling voltage levels and MVar flows within their individual areas and the areas of neighboring Transmission Operators (Requirement R1);
- Acquire sufficient reactive resources within its areas to protect voltage levels under normal and Contingency conditions (Requirement R2);
- Specify criteria to exempt generators from compliance with the voltage or Reactive Power schedule developed by the Transmission Operator in accordance with VAR-001-3, maintain a list of exempted generators, and notify Generator Owners of any exempted generators (Requirement R3);
- Specify a voltage or Reactive Power schedule at the interconnection between the generator facilities and Transmission Owner's facilities, provide the schedule to the associated Generator Operator, and direct it to comply with the schedule in automatic voltage control mode (Requirement R4);

---

[26] Order No. 672 at P 334.

[27] As noted above, VAR-001-3 also includes a regional variance applicable to Generator Operators in the Western Interconnection. Because NERC is not proposing any substantive changes to that regional variance, it is not discussed herein.

[28] The Commission approved retirement of Requirement R5 effective January 21, 2014. *See Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147, at P 17 (2013).

- Know the status of all transmission Reactive Power resources and, when notified of the loss of an automatic voltage regulator ("AVR") control, direct the Generator Operator to maintain or change its voltage or Reactive Power schedule (Requirement R6);

- Operate or direct operations of devices to regulate transmission voltage and reactive flow (Requirement R7);

- Operate or direct operations of capacitive and inductive reactive resources within its area to maintain system and Interconnection voltages within established limits (Requirement R8);

- Maintain reactive resources to support its voltage under first Contingency conditions and disperse and locate these resources to allow for effective and quick application when Contingencies occur (Requirement R9);

- Correct and report SOL and IROL violations resulting from reactive resource deficiencies (Requirement R10);

- Consult with and provide documentation to Generator Owners about required tap changes, timeframes for completion, and technical justification for these changes (Requirement R11); and

- Direct corrective action necessary to prevent voltage collapse when reactive resources are insufficient.

Currently enforceable Reliability Standard VAR-001-3, however, does not address the following outstanding Commission directives from Order Nos. 693 and 724:

- Include Reliability Coordinators as responsible entities;[29]

- Address the power factor range at the interface between Load Serving Entities ("LSEs") and the Bulk-Power System;[30]

- Consider acceptable ranges of net power factors where LSEs receive service from the Bulk-Power System;[31]

- Specify and define requirements on "established limits" and "sufficient reactive resources" and identify voltage and Reactive Power margins to prevent voltage instability;[32]

---

29 Order No. 693 at P 1855.

30 *Id.* at P 1861.

31 *Id.* at PP 1860, 1862.

32 *Id.* at P 1868.

- Require the performance of periodic voltage stability analysis using online and offline techniques to assist Real-time operations;[33] and

- Ensure voltage schedules reflect sound engineering and operating judgment and experience.[34]

As discussed below, proposed Reliability Standard VAR-001-4 or other existing or pending Reliability Standards address these outstanding Commission directives.

2. Reliability Standard VAR-002-2b

Currently enforceable Reliability Standard VAR-002-2b requires that generators provide reactive and voltage control necessary to maintain voltage levels, reactive flows and reactive resources within applicable facility ratings to protect equipment and the reliable operation of the Interconnection. Under the existing requirements, each Generator Operator is required to:

- Operate in automatic voltage control mode unless it is exempted or the Generator Operator notifies its Transmission Operator that it is (1) operating the generator in start-up or shutdown mode pursuant to a Real-time communication or a procedure previously provided to the Transmission Operator, or (2) not operating the generator in automatic voltage control mode for a reason other than start-up or shutdown (Requirement R1);

- Maintain the voltage or Reactive Power schedule, unless otherwise exempted by the Transmission Operator, use an alternative method for controlling the generator voltage and Reactive Power output when a generator's AVR is out of service, and, when directed to modify voltage, provide an explanation to the Transmission Operator if it cannot meet the schedule (Requirement R2); and

- Notify its Transmission Operator as soon as practical, but within 30 minutes, of a status or capability change on any Reactive Power resource (generator or other), including the status of each AVR and power system stabilizer, and the expected duration of the identified change (Requirement R3).

Reliability Standard VAR-002-2b also requires each Generator Owner to:

- Provide tap-related information on step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage within 30

[33] *Id.* at P 1875.

[34] Order No. 724 at P 49.

calendar days of a request from the Transmission Operator and Transmission Planner (Requirement R4); and

- Ensure that transformer tap positions are changed according to the Transmission Operator's specifications, unless this action would violate safety, an equipment rating, or a regulatory or statutory requirement, in which case the Generator Owner must notify the Transmission Operator and justify why the Generator Owner is unable to comply (Requirement R5).

Currently enforceable Reliability Standard VAR-002-2b does not address the Commission's directive to consider an additional time frame associated with an "incident" of non-compliance with VAR-002.[35] As discussed below, this directive is addressed in proposed Reliability Standard VAR-001-4.

D. Procedural History of Project 2013-04 – Voltage and Reactive Control (VAR)

In February 2013, NERC initiated an informal development process to revive efforts to modify the existing VAR Reliability Standards to address the outstanding Commission directives from Order Nos. 693 and 724 related to those standards.[36] Participants in this informal process were industry subject matter experts, NERC staff, and FERC staff from the Office of Electric Reliability. The informal development group met numerous times between February 2013 and July 2013 to discuss the outstanding Commission directives and ways to improve the existing VAR Reliability Standards. The informal group also conducted industry outreach to obtain feedback on the existing standards.

After evaluating the VAR Reliability Standards and the Commission's directives, the informal group concluded that certain of the existing requirements and outstanding directives overlapped with or were duplicative of requirements in other Reliability Standards to maintain and operate within SOLs and IROLs or were otherwise unnecessary from a reliability

---

35 Order No. 693 at PP 1883, 1885.

36 In 2008, NERC initiated Project 2008-01 to address the directives from Order No. 693 related to the VAR Reliability Standards. That project was not completed due to project reprioritization.

perspective. To that end, the informal participants developed revised drafts of the VAR Reliability Standards to address Commission directives, eliminate duplicative or unnecessary requirements, and improve the quality and content of those existing requirements that are necessary to help maintain voltage stability on the Bulk-Power System.

As discussed further in Exhibit F, Project 2013-04 formally commenced on July 19, 2013 with the posting of a Standard Authorization Request ("SAR") along with the initial drafts of the proposed Reliability Standards developed by the informal participants for a 45-day comment period and ballot. A formal standard drafting team was formed following the posting of the SAR and the initial drafts of the proposed Reliability Standards.[37]

Following the close of the initial ballot, the standard drafting team addressed industry comments and posted second drafts of the proposed Reliability Standards on October 11, 2013 for an additional 45-day comment period and ballot. Proposed Reliability Standard VAR-001-4 received the requisite approval during the second ballot and was subsequently posted for a final ballot. The final ballot concluded on December 23, 2013 and received an approval rating of 75.35%. The NERC Board of Trustees approved proposed Reliability Standard VAR-001-4 on February 6, 2014.

The standard drafting team addressed additional industry comments on the second draft of proposed Reliability Standard VAR-002-3 and, on February 27, 2014, posted a third draft of the standard for a 45-day comment period and ballot. Proposed Reliability Standard VAR-002-3 received the requisite approval in the third ballot and was subsequently posted for a final ballot. The final ballot concluded on May 5, 2014 and received an approval rating of 88.26%. The NERC Board of Trustees approved proposed Reliability Standard VAR-002-3 on May 7, 2014.

[37] Exhibit G provides the standard drafting team roster.

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, proposed Reliability Standards VAR-001-4 and VAR-002-3 satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following sections provide: (1) the basis and purpose of the proposed Reliability Standards; (2) a discussion of the requirements in the proposed Reliability Standards; (3) an explanation of how the proposed Reliability Standards satisfy outstanding Commission directives from Order Nos. 693 and 724; and (4) a discussion of the enforceability of the proposed Reliability Standards.

A. Basis and Purpose of the Proposed Reliability Standards

Proposed Reliability Standards VAR-001-4 and VAR-002-3 replace and improve upon the prior versions of the standards (VAR-001-3 and VAR-002-2b) by addressing outstanding Commission directives from Order Nos. 693 and 724, improving reliability, clarifying language in certain requirements, and eliminating redundant or unnecessary requirements. As is further discussed in Section IV.C below, the outstanding Commission directives are addressed by proposed Reliability Standards VAR-001-4 and VAR-002-3, or already have been addressed in other currently enforceable or pending Reliability Standards. So as to avoid unnecessary redundancies or duplicative requirements, NERC does not propose to address in VAR-001-4 and VAR-002-3 those directives already addressed by other existing or pending Reliability Standards.

The standard drafting team sought to modify the currently enforceable Reliability Standards VAR-001-3 and VAR-002-2b to improve the clarity, quality, and content of the standards. These efforts include, but are not limited to, the following:

- VAR-001-4, Requirement R1 removes voltage level controls and monitoring obligations duplicative with other currently enforceable Reliability Standards and improves reliability by requiring Transmission Operators to (1) specify system voltage schedules, which may be either a range or a target value with associated tolerance bands, and (2) coordinate with adjacent Transmission Operators and Reliability Coordinators regarding those system voltage schedules.

- VAR-001-4, Requirements R2 and R3 simplify and consolidate several existing requirements while ensuring sufficient reactive resources are scheduled (Requirement R2) and voltage support is provided (Requirement R3).

- VAR-001-4, Requirement R4 removes unnecessary compliance complexities and offers Transmission Operators the flexibility to tailor exemption criteria to area-specific needs.

- VAR-001-4, Requirement R5 improves transparency of Transmission Operator voltage or Reactive Power schedules for generators and provides the Transmission Operator the flexibility to develop notification requirements for deviations from those schedules based on the unique characteristics and needs of its system.

- VAR-001-4, Requirement R6 maintains and improves upon the existing tap setting requirements to avoid an adverse reliability impact caused by an improper tap setting that in turn may affect the Reactive Power output of a generator.

- VAR-002-3, Requirement R1 improves upon the prior version of the Reliability Standard by providing an option for certain Generator Operators to operate in modes other than automatic voltage control mode, as may be instructed by the Transmission Operator. Further, in addition to start-up or shutdown, Requirement R1 adds testing as a time when a generator need not operate in automatic voltage control mode or a different mode instructed by the Transmission Operator.

- VAR-002-3, Requirement R2 carries forward the requirement that Generator Operators maintain the generator voltage or Reactive Power schedule provided by the Transmission Operator pursuant to VAR-001-4, Requirement R5 but allows the Generator Operator to deviate from that schedule if it is exempted or satisfies the notification requirements established by the Transmission Operator under VAR-001-4, Requirement R5, Part 5.2. VAR-002-3, Requirement R2 also clarifies that Generator Operators that do not monitor voltage at the location specified in their voltage schedule provided by the Transmission Operator may convert the schedule to the voltage point monitored by the Generator Operator using a documented conversion methodology.

- VAR-002-3, Requirements R3 and R4 limit status change notification requirements to those changes lasting longer than 30 minutes because notification of changes resolved within a 30-minute window provides minimal, if any, reliability benefit.

- VAR-002-3, Requirements R5 and R6 include clarifying edits to remove an unnecessary sub-part (Requirement R5) and uniformly reference the applicable entity (Requirement R6).

B. Requirements in the Proposed Reliability Standards

1. Reliability Standard VAR-001-4

Proposed Reliability Standard VAR-001-4 consists of six requirements and is applicable to Transmission Operators and, for the WECC regional variance maintained and carried forward from Reliability Standard VAR-001-3, Generator Operators within the Western Interconnection. An explanation of the six requirements and the omission of certain VAR-001-3 requirements are provided below.[38]

VAR-001-4, Requirement R1

> **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.
>
> **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.

Requirement R1 is intended to replace and simplify the currently-effective VAR-001-3, Requirement R1, which requires Transmission Operators, individually and jointly, to develop formal policies and procedures for controlling and monitoring voltage levels and MVar flows. In evaluating VAR-001-3, Requirement R1, the standard drafting team concluded that because controlling and monitoring voltage levels and MVar flows is already required by the Transmission Operations ("TOP") group of Reliability Standards, it should not be duplicated in proposed Reliability Standard VAR-001-4. Specifically, currently effective Reliability Standard TOP-004-2, Requirement R6 also requires "Transmission Operators, individually and jointly

[38] The WECC regional variance is not reproduced herein as it has not been substantively modified from the currently enforceable VAR-001-3 regional variance. Only non-material changes have been made to reference the replacement of VAR-001-4, Requirements R4 and R5, rather than VAR-001-3, Requirements R3 and R5.

with other Transmission Operators, [to] develop, maintain, and implement formal policies and procedures to provide for transmission reliability." That requirement specifies that the "policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including," among other things, "monitoring and controlling voltage levels and real and reactive power flows."

Additionally, currently effective TOP Reliability Standards require that Transmission Operators plan to meet SOLs and IROLs (TOP-002-2.1b, Requirement R10) and operate within SOLs and IROLs (TOP-004-2, Requirement R1).[39] As stated in the NERC Glossary, a SOL is defined as:

> the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. [SOLs] are based upon certain operating criteria. These include, but are not limited to: [1] Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings); [2] Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits); [3] Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability); and [4] System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits).[40]

Accordingly, to meet the obligations under Reliability Standards TOP-002-2.1b, Requirement R10 and TOP-004-2, Requirement R1 to plan to meet and operate within SOLs and IROLs, a Transmission Operator is required to monitor and control voltage levels and MVar flows. Failure to do so could lead to a violation of these requirements.

Similarly, monitoring and controlling voltage and MVar flows is fundamental to complying with TOP-004-2, Requirements R2 and R3, which require a Transmission Operator to

---

[39] Reliability Standard FAC-014-2, Requirement R2 requires a Transmission Operator to establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

[40] An IROL is defined in the NERC Glossary as "[a] SOL that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System" (footnote omitted).

operate to protect against instability, uncontrolled separation, or cascading outages from (1) the most severe single contingency (Requirement R2), and (2) multiple outages, as specified by its Reliability Coordinator (Requirement R3). Failure to monitor and control voltage and MVar flows could result in a violation of these requirements.

Certain of the TOP Reliability Standards are currently being modified as part of a standards development project at NERC. While certain language and obligations from the existing TOP Reliability Standards may change, the obligation to monitor and control voltage levels and reactive flows will remain. Specifically, as proposed, draft Reliability Standards TOP-001-3 and TOP-002-4 would collectively require Transmission Operators to plan to meet and operate within SOLs and IROLs.[41] In addition, those draft Reliability Standards would require each Transmission Operator to (1) monitor facilities within its area and neighboring areas to maintain reliability in its area, and (2) perform a Real-time Assessment at least once every 30 minutes. To comply with these obligations, Transmission Operators must monitor and control voltage, as discussed above.

Because controlling and monitoring voltage and MVar flows is covered elsewhere, the standard drafting team modified VAR-001-4, Requirement R1 to only require that Transmission Operators (1) specify a system voltage schedule as part of its plan to operate with SOLs and IROLs, and (2) provide such schedules to adjacent Transmission Operators and applicable Reliability Coordinators, upon request. The requirement to specify a system voltage schedule as a range or a target value with an associated tolerance band will help ensure that the system maintains an appropriate voltage level in Real-time. The reactive behavior of any particular system depends on a myriad of local conditions which change over time. The intent of

[41] As of the date of this Petition, proposed Reliability Standards TOP-001-3 and TOP-002-4 have been posted for an initial comment period and ballot, which is scheduled to close on July 2, 2014.

Requirement R1 is not to mandate that Transmission Operators set and maintain a static voltage level; rather it is to require Transmission Operators to identify the acceptable voltage limits (either by identifying a range or a target value with an associated tolerance band) that supports reliable operations in Real-time.

The requirement to share the voltage schedule with neighboring Transmission Operators and Reliability Coordinators will allow for increased and improved coordination between neighboring areas. Given the interconnected nature of the Bulk-Electric System, voltage coordination is necessary to help ensure that sufficient Reactive Power is available to support both Real-time and day-ahead operations.

***VAR-001-4, Requirement R*2**

> **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.

Requirement R2 modifies and consolidates the obligations in currently-effective VAR-001-3, Requirements R2 and R9 to require the scheduling of sufficient reactive resources. As noted above, the primary factor in maintaining voltage stability is having the appropriate amount of Reactive Power on the system. Proposed Requirement R2 helps ensure that sufficient reactive resources are online and scheduled in Real-time.

VAR-001-3, Requirements R2 and R9 require each Transmission Operator to (1) "acquire sufficient reactive resources . . . within its area to protect the voltage levels under normal and Contingency conditions" and (2) "maintain reactive resources . . . to support its voltage under first Contingency conditions," respectively. The standard drafting team concluded that these requirements should be combined into a single requirement that more directly states the desired performance for ensuring that sufficient Reactive Power is on the system in Real-time to maintain voltage stability (*i.e.*, to "schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions").[42]

Requirement R2 also clarifies the language with respect to the manner in which Transmission Operators may schedule sufficient reactive resources (*e.g.*, through reactive generation scheduling, transmission line and reactive resource switching, and using controllable load). Consistent with the Commission's directive in Order No. 693,[43] Requirement R2 includes the use of controllable load in the non-exhaustive list of ways to provide sufficient reactive resources. As the Commission stated, "in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system."[44]

VAR-001-4, Requirement R3

> **R3.** Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary.

Whereas Requirement R2 obligates the Transmission Operator to ensure that there are sufficient reactive resources online and scheduled, Requirement R3 requires that a Transmission Operator actually provide sufficient voltage support in Real-time by operating its own devices or directing others to do so.

Requirement R3 carries forward the obligation from VAR-001-3, Requirement R7. However, by deleting the phrase "be able to" Requirement R3 creates an affirmative obligation to operate or direct the operation of devices to regulate transmission voltage and reactive flow

---

[42] VAR-001-4, Requirement R2.

[43] Order No. 693 at P 1879.

[44] *Id*.

when necessary.[45] Additionally, the standard drafting team concluded that there was no need to separately carry forward VAR-001-3, Requirement R8 because it was subsumed in proposed VAR-001-4, Requirement R3.

VAR-001-4, Requirement R4

> **R4.** The Transmission Operator shall specify the criteria that will exempt generators from: 1) 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.
>
> > **4.1** If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

As discussed below, proposed Reliability Standard VAR-002-3 imposes requirements on the Generator Operator for providing reactive support, including: (1) following the voltage or Reactive Power schedule provided by the Transmission Operator; (2) operating its generator(s) in automatic voltage control mode; and (3) notifying the Transmission Operator of any deviations from the schedule or changes to the status of its voltage control mode. In certain circumstances, however, it may not be necessary or desired for a Generator Operator to comply with such requirements. For instance, a Generator Operator may need to be exempt from performance for the following system events, among others: (1) maintenance during shoulder months; (2) scenarios where two generators are located within close proximity and cannot both operate in voltage control mode; and (3) system voltage swings where it would harm reliability if all Generator Operators provided deviation notifications to their respective Transmission Operators at one time.

---

45 VAR-001-3, Requirement R7 states as follows: "The Transmission Operator shall ***be able to*** operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow" (emphasis added).

Requirement R4 carries forward the authority in currently enforceable Reliability Standard VAR-001-3, Requirement R3 for a Transmission Operator to exempt a Generator Operator from having to comply with all or some of its Reactive Power obligations. Proposed Requirement R4 clarifies that a Transmission Operator may exempt a Generator Operator from the following requirements: (1) complying with a voltage or Reactive Power schedule; (2) operating in automatic voltage control mode; and (3) certain notification requirements. Requirement R4 also allows each Transmission Operator to tailor its criteria for exemptions to its area's specific needs.

Further, Requirement R4 simplifies Reliability Standard VAR-001-3, Requirement R3 by removing the need for Transmission Operators to maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule. Removal of this list requirement alleviates unnecessary compliance burdens and complexities related to how often to update and maintain these lists. Instead, proposed Requirement R4 focuses on whether the exemption criteria are transparent and whether the Transmission Owner notified the Generator Operator that it is exempt.

VAR-001-4, Requirement R5

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.

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.

Requirement R5 carries forward the obligation from currently-effective Reliability Standard VAR-001-3, Requirement R4 that Transmission Operators must provide a voltage or Reactive Power schedule for each generator and direct the associated Generator Operator to comply with that schedule in automatic voltage control mode unless otherwise instructed or exempted. Proposed Requirement R5 modifies that requirement to clarify that a Transmission Operator may provide the voltage or Reactive Power schedule at either the high or low voltage side of the generator step-up transformer.[46] Specifying the location of the voltage or Reactive Power schedule provides a mechanism for the Generator Operator to convert the scheduled voltage to the voltage point it monitors. As discussed below, VAR-002-3, Requirement R2, Part 2.2 clarifies that if the Generator Operator does not monitor voltage at the location specified in the schedule provided by the Transmission Operator, the Generator Operator may use a conversion methodology for converting the scheduled voltage to the voltage point monitored by the Generator Operator.

As with the system level voltage schedule, the voltage or Reactive Power schedule provided to Generator Operators must be a range or a target value with an associated tolerance band. Specifying the voltage schedule as a range or as a target value with an associated tolerance

[46] VAR-003-1, Requirement R4 simply states that the Transmission Operator must "specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Operator's facilities" (footnote omitted).

band provides information that Generator Operators can use to set their control devices to appropriate settings to maintain operation within the specified tolerances.

Further, Part 5.2 requires Transmission Operators to provide Generator Operators the notification requirements for deviations from the voltage or Reactive Power schedule. Part 5.2 ensures that Generator Operators are aware of the notification requirements for deviating from the required schedule while also providing Transmission Operators the flexibility to develop notification requirements that best suit their needs.

Lastly, Requirement R5 provides for increased transparency of the Transmission Operator's development of voltage and Reactive Power schedules. Part 5.3 requires Transmission Operators to provide Generator Operators the criteria for developing the voltage or Reactive Power schedule, if requested. Part 5.3 will help ensure that the Transmission Operator has a technical basis for setting the required voltage and Reactive Power schedule that takes into account system needs and any limitations of the specific generator. Providing such criteria may alleviate some operational disputes between Transmission Operators and Generator Operators regarding the technical justifications for the voltage and Reactive Power schedules.

VAR-001-4, Requirement R6

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.

Requirement R6 updates currently-effective VAR-001-3, Requirement R11 to allow for scheduling consultation. Because an improper tap setting may affect the amount of VARs produced by a generator, the standard drafting team concluded that this requirement needed to be included in proposed Reliability Standard VAR-001-4.

Omitted VAR-001-3 Requirements

Several currently enforceable requirements from Reliability Standard VAR-001-3 have been omitted from proposed Reliability Standard VAR-001-4 because they have been retired (Requirement R5)[47] or are duplicative with other currently enforceable and pending Reliability Standards (existing Requirements R6, R10 and R12). On this last category of omitted requirements:

- VAR-001-3, Requirement R6 is duplicative of currently enforceable TOP-006-2, Requirement R1, which requires that Transmission Operators know the status of all generating and transmission resources, including Reactive Power resources, available for use. In addition, TOP-006-2, Requirement R2 requires, among other things, each Reliability Coordinator, Transmission Operator, and Balancing Authority to monitor applicable real and reactive power flows, voltage, and the status of rotating and static reactive resources, which requires monitoring of power system stabilizers ("PSS") in areas that rely on PSS equipment. The TOP Reliability Standards currently in development would require each Transmission Owner to monitor Facilities, sub-100 kV facilities, and the status of Special Protection Systems within its area and neighboring areas, as needed to maintain reliability within its Transmission Operator Area.[48] This monitoring activity requires Transmission Operators to know the status of Reactive Power resources.

- VAR-001-3, Requirement R10 is duplicative of currently enforceable TOP-004-2, Requirement R1, which provides that Transmission Operators shall operate within SOLs and IROLs. This would include taking action to correct SOL and IROL violations resulting from reactive resource deficiencies. Additionally, TOP-004-2, Requirement R4 requires Transmission Operators that enter an unknown operating state (*i.e.*, any state for which valid operating limits have not been determined) to restore operations to respect proven reliable power system limits within 30 minutes. The TOP Reliability Standard currently in development will continue to require Transmission Operators to operate within SOLs and IROLs and take action to correct and report such violations.[49]

---

[47] The Commission approved the retirement of Requirement R5 of VAR-001-2. *See* Order No. 788 at P 17 (accepting retirement of VAR-001-2, Requirement R5, effective January 21, 2014, because it is redundant with the *pro forma* Open Access Transmission Tariff and any resulting reliability gap is addressed by currently enforceable VAR-001-3, Requirement R2). (Currently effective VAR-001-3, Requirement R5 also notes that Requirement R5 will be retired effective January 21, 2014.) Proposed VAR-001-4, Requirement R2 will also achieve the reliability objective envisioned by retired Requirement R5.

[48] *See* draft Reliability Standard TOP-001-3, Requirement R10, *available at* http://www.nerc.com/pa/Stand/Pages/Project-2014-03-Revisions-to-TOP-and-IRO-Standards.aspx.

[49] *See* draft Reliability Standard TOP-001-3, Requirements R12–R15.

- VAR-001-3, Requirement R12 is also duplicative with requirements in TOP-004-2 to take corrective action, including load-shedding, to operate within SOLs and IROLs and prevent voltage collapse. The TOP Reliability Standard currently in development will continue to require Transmission Operators to take action to prevent voltage collapse.[50] Additionally, Reliability Standard EOP-003-2 covers plans for load shedding to prevent voltage collapse.

2. Reliability Standard VAR-002-3

Proposed Reliability Standard VAR-002-3 consists of six requirements and is applicable to Generator Operators and Generator Owners. An explanation of each of the six requirements is provided below.

VAR-002-3, Requirement R1

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:

- That the generator is being operated in start-up,[FN1] shutdown,[FN2] 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.

[FN1: 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.]

[FN2: 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.]

Requirement R1 carries forward the obligation in currently effective VAR-002-2b, Requirement R1 for Generator Operators to operate generators in automatic voltage control

[50] *See id*.

mode, but modifies the requirement to allow a Generator Operator to operate in a different control mode if instructed by the Transmission Operator. From a reliability perspective, it is beneficial for generators to operate in automatic voltage control mode. Once set in "voltage controlling" mode, the AVR should automatically adjust to voltage swings within its pre-defined voltage band. A different control mode, however, may be appropriate in certain circumstance. For instance, where two large generators are located within close proximity, if both generators operate in voltage control mode it may result in undesirable effects, such as voltage swings due to the units competing to control voltage. In such instances, to improve voltage regulation and stability, it may be beneficial to allow one of the units to be in automatic voltage control mode while directing the other unit to operate in an alternative mode. Proposed Reliability Standard VAR-002-3 therefore provides for a default mode of operation (*i.e.*, automatic voltage control mode) while also providing flexibility for Transmission Operators and Generator Operators to coordinate if a different control mode would be more effective.

Additionally, Requirement R1 modifies currently effective VAR-002-2b, Requirement R1 to add testing as a time when a generator need not operate in automatic voltage control mode or a different mode instructed by the Transmission Operator.

VAR-002-3, Requirement R2

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[FN3] (within each generating Facility's capabilities[FN4]) 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.

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.

[FN3: 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.]

[FN4: 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.]

Requirement R2 carries forward the affirmative obligation from VAR-003-1, Requirement R2 that the Generator Operator maintain the voltage or Reactive Power schedule provided by the Transmission Operator, unless the Transmission Operator exempts the Generator Operator from doing so. Proposed Requirement R2 adds that the Generator Operator need not comply with the schedule if it satisfies the notification requirements for deviations established by the Transmission Operator under Reliability Standard VAR-001-4, Requirement R5, Part 5.2. By removing prescriptive notification requirements for the entire continent and providing additional flexibility, proposed Requirement R2, together with VAR-001-4, Requirement R5, Part 5.2, allows each Transmission Operator to determine the notification requirements for each of its respective Generator Operators based on system requirements and generator needs.

Additionally, proposed Requirement R2 includes a new Part 2.3 to allow Generator Operators that do not monitor voltage at the location specified in their voltage schedule provided by the Transmission Operator to convert the schedule to the voltage point monitored by the Generator Operator. As noted above, proposed Reliability Standard VAR-001-4, Requirement

R5 clarifies that the Transmission Operator may specify the schedule at either the high or low voltage side of the generator step-up transformer. Part 2.3 of proposed VAR-002-3 was included to allow a generator to continue monitoring voltage based on existing equipment, provided it has a methodology for conversion. There are many ways to convert the voltage schedule, including the development of voltage regulation curves for the transformers or the use of straight ratio conversion. This standard provides Generator Operators with the ability to meet a voltage schedule based on metering equipment while providing the necessary voltage support.

VAR-002-3, Requirements R3 and R4

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.

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.

Proposed Requirements R3 and R4 separate the notification requirements in currently-effective VAR-002-2b, Requirement R3 into two requirements: (1) for AVR/PSS status changes (proposed Requirement R3), and (2) for reactive capability changes (proposed Requirement R4). Each of the proposed requirements provides for a 30-minute window to allow a Generator Operator time to resolve an issue before having to notify the Transmission Operator of a change. For example, proposed Requirement R3 limits the notifications required when an AVR goes out of service and quickly comes back in service (*i.e.*, within 30 minutes) because notification of this type of status change provides little to no benefit to reliability. For the same reason, proposed

Requirement R3 also removes existing Part 3.1, which requires that the Generator Operator provide an estimate for the expected duration of the status change.

Proposed Requirement R4 also limits the notifications required when a reactive capability change occurs and is quickly restored (*i.e.*, within 30 minutes) because notification of this type of status change provides little to no benefit to reliability. Proposed Requirement R4 improves VAR-002-2b, Requirement R3, which requires notification as soon as the reactive capability change occurs, to allow Generator Operators to report reactive capability changes after they become aware of the change. Proposed Requirement R4 also removes existing Part 3.2, which requires that the Generator Operator provide an estimate for the expected duration of the status change.

VAR-002-3, Requirement R5

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

5.1. For generator step-up transformers and auxiliary transformers 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.

Requirement R5 maintains most of currently-effective VAR-002-2b, Requirement R4 because of the importance of accurate tap settings. That is, if the tap setting is not properly set, then the VARs available from a particular generator may be affected. Proposed Requirement R5 removes existing Sub-part 4.1.4, which requires that a Generator Owner provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." This percentage information is extraneous because tap settings, available fixed tap ranges and impedance data already are required[51] and can be used to calculate the step-change percentage, if needed.

VAR-002-3, Requirement R6

> **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.
>
> > **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.

Requirement R6 maintains most of currently-effective VAR-002-2b, Requirement R5 due to the importance of accurate tap settings, as explained above. However, Requirement R6 updates VAR-002-2b, Requirement R5 to clarify that the requirement and corresponding part apply to the same functional entity (Generator Owners).[52]

C. Proposed VAR-001-4 and VAR-002-3 Satisfy Outstanding Commission Directives

Project 2013-04 was initiated to address outstanding Commission directives from Order Nos. 693 and 724. The following is a discussion of each outstanding directive and the manner in which proposed Reliability Standards VAR-001-4 and VAR-002-3 address them.[53]

Applicability to Reliability Coordinators: In Order No. 693, the Commission directed NERC to modify Reliability Standard VAR-001 to "include reliability coordinators as applicable

---

[51] VAR-002-2b, Requirement R4, Sub-parts 4.1.1–4.1.3; VAR-002-3, Requirement R5, Sub-parts 5.1.1–5.1.3.

[52] Existing Requirement R5 references "Generator Owner" in Requirement R5 and "Generator Operator" in Part 5.1. Proposed Requirement R6 modifies the reference to "Generator Operator" in Part 5.1 to reference "Generator Owner" in what is now Part 6.1.

[53] Since the issuance of Order No. 693, the Commission withdrew its directives from paragraphs 1863 and 1869 of Order No. 693 related to the VAR Reliability Standards. *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25–26, Att. A (2013).

entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities."[54] The Commission reasoned that because "a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage and reactive resources are being maintained."[55] Because the Interconnection Reliability Operations and Coordination ("IRO") group of Reliability Standards address Reliability Coordinator monitoring functions, the standard drafting team concluded that any additional requirements on the Reliability Coordinator monitoring function regarding voltage should be addressed in the IRO Reliability Standards. There is currently a NERC standards development project, Project 2014-03 – Revisions to TOP and IRO Standards, which is modifying the IRO Reliability Standards. The standard drafting team for that project is considering whether any revisions are necessary to address this directive.[56] Therefore, NERC does not propose to apply VAR-001-4 to Reliability Coordinators or develop any additional VAR-001-4 requirements applicable to Reliability Coordinators at this time.

Reactive Power requirements for LSEs: As directed by the Commission,[57] NERC addressed Reactive Power requirements for LSEs on a comparable basis with purchasing-selling

---

54 Order No. 693 at P 1855.

55 *Id*.

56 Specifically, the drafting team for Project 2014-03 has proposed a new IRO-002-4, Requirement R4, which provides:

> Each Reliability Coordinator shall monitor Facilities within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to determine any potential [SOL and IROL] exceedances within its Reliability Coordinator Area, including sub-100 kV facilities needed to make this determination and the status of Special Protection Systems in its Reliability Coordinator Area.

57 Order No. 692 at P 1858.

entities in Reliability Standard VAR-001-2, Requirement R5.[58] Subsequently, the Commission approved retirement of the requirement addressing this directive because the directive is effectively addressed in Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service) of the Commission's *pro forma* Open Access Transmission Tariff.[59] As such, NERC does not propose to address this directive in the proposed Reliability Standards.

Power factor range at the interface between LSEs and the Bulk-Power System: The Commission directed NERC to develop a modification to the VAR Reliability Standards "to address the power factor range at the interface between LSEs and the Bulk-Power System."[60] The Commission was concerned that during high loads, if the power factor at the interface between many LSEs and the Bulk-Power System is so low as to result in low voltages at key busses on the Bulk-Power System, then there is risk for voltage collapse. Since the issuance of this directive, however, other Reliability Standards approved by the Commission address this issue. Specifically, Reliability Standard TPL-001-4, which has been approved by the Commission and subject to future enforcement, requires that system models include Real and reactive Load forecasts.[61] These system model inputs provide the appropriate power factors to be maintained. Additionally, Reliability Standard FAC-001-1 requires that each Transmission Owner and applicable Generator Owner provide a written summary of its plan to achieve the required system performance for "Voltage, Reactive Power, and ***power factor control***."[62] Because currently enforceable Reliability Standards TPL-001-4 and FAC-001-1 address the

---

58 *NERC Petition for Approval of Proposed Modifications to Reliability Standards BAL-002-1; EOP-002-3; FAC-002-1; MOD-021-2; PRC-004-2; and VAR-001-2*, 134 FERC ¶ 61,015 (2011).

59 Order No. 788 at P 17.

60 Order No. 693 at P 1861.

61 TPL-001-4, Requirement R1, Part 1.1.4, *available at* http://www.nerc.com/files/TPL-001-4.pdf.

62 *See* FAC-001-1, Requirement R3, Part 3.1.9, *available at* http://www.nerc.com/files/FAC-001-1.pdf (emphasis added).

appropriate power factors to be maintained, the VAR standard drafting team determined it would be duplicative and unnecessary for reliability purposes to add the same or similar requirements to proposed Reliability Standards VAR-001-4 and VAR-002-3.

Consideration of acceptable ranges of net power factor range: The Commission directed NERC to consider the difficulty of reaching "an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors."[63] The standard drafting team considered this directive carefully and determined that it has been addressed by the interconnection process and related agreements, as well as by currently enforceable Reliability Standards TPL-001-4 and FAC-001-1, as discussed above. Therefore, the standard drafting team did not include any additional language to proposed Reliability Standards VAR-001-4 and VAR-002-3 to address this directive.

Detailed and definitive requirement on established limits and sufficient reactive resources: The Commission directed NERC to "include more detailed and definitive requirements on 'established limits' and 'sufficient reactive resources' and identify acceptable margins (*i.e.*, voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operation."[64] The Commission, in part, was addressing concerns that the Transmission Operator should be required to have a technical basis for setting the required voltage schedule that takes into account system needs and any limitations of the specific generator.[65] Proposed Reliability Standard VAR-001-4 addresses this concern by requiring Transmission Operators to (1) share their system voltage schedules with their

---

63 Order No. 693 at PP 1860, 1862.

64 *Id*. at P 1868.

65 *See id*. at P 1864.

Reliability Coordinators and adjacent Transmission Operators (Requirement R1, Part 1.1), and (2) provide Generator Operators the criteria used to develop generator-specific voltage and Reactive Power schedules (Requirement R5, Part 5.3). This increased transparency will help ensure that Transmission Operators have a technical basis for setting system-wide and generator specific voltage and Reactive Power schedules that takes into account system needs and any limitations of the specific generator.

Additionally, the Commission stated that "the Reliability Standard would benefit from having more defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions."[66] Currently enforceable FAC and TOP Reliability Standards approved by the Commission following the issuance of Order No. 693, however, address this directive by requiring entities to develop methodologies for establishing SOLs and IROLs that include detailed and definitive requirements for voltage limits and margins. Specifically, Reliability Standard FAC-011-2, Requirement R1 requires the Reliability Coordinator to have a documented methodology for use in developing SOLs (the "SOL Methodology") within its Reliability Coordinator Area for use in the operations horizon.[67] Among other things, the SOL Methodology must include a requirement that SOLs provide BES performance consistent with maintaining voltage stability.[68]

---

[66] *Id*. at P 1870.

[67] Reliability Standard FAC-010-2.1 requires the Reliability Coordinator to have a documented SOL Methodology for use in the planning horizon.

[68] Specifically, FAC-011-2, Requirement R2 provides that:

> [t]he Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:

continued . . .

Reliability Standard FAC-014-2 then requires (1) each Reliability Coordinator to ensure that SOLs, including IROLs, for its Reliability Coordinator Area are established and consistent with its SOL Methodology, and (2) each Transmission Operator to establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

These FAC Reliability Standards operate in tandem with the TOP Reliability Standards, which, as discussed above, require that each Transmission Operator plan to meet and operate within SOLs and IROLs. The standard drafting team determined that these currently enforceable FAC and TOP Reliability Standards collectively provide sufficient detail on "established limits" and margins, and it was unnecessary to include any additional definitive and detailed requirements in VAR-001-4 or VAR-002-3 to address voltage instability and ensure reliable operations. The standard drafting team determined, however, that because acceptable voltage limits and the level of sufficient Reactive Power necessary to maintain voltage depends on the unique characteristics of each system, the proposed Reliability Standards cannot dictate a specific, "one-size-fits-all" approach to determining what constitutes a sufficient level of Reactive Power. Rather, the SOL Methodologies developed by Reliability Coordinators under FAC-011-2 will provide the necessary detail tailored to the needs of the system in question.

Periodic voltage stability analysis: The Commission directed NERC to include a requirement to "perform voltage stability analysis periodically, using online techniques where

---

> R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and ***voltage stability***; all Facilities shall be within their Facility Ratings and within their thermal, voltage and ***stability limits***. . . .
>
> R2.2. [T]he system shall demonstrate transient, dynamic and ***voltage stability***; all Facilities shall be operating within their Facility Ratings and within their thermal, ***voltage and stability limits***; and Cascading or uncontrolled separation shall not occur.

(Emphasis added.)

commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations."[69] The Commission stated that "[t]he ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools."[70] The standard drafting team concluded that requiring periodic voltage stability analysis in proposed VAR-001-4 was duplicative of requirements in the TOP group of Reliability Standards. Specifically, period voltage stability analysis is already required to comply with Reliability Standards TOP-002-2.1b, Requirements R10[71] and R11,[72] TOP-004-2, Requirement R6,[73] and TOP-006-2, Requirement R2.[74] Each of these existing Reliability Standards requires active planning and monitoring to operate within SOLs. Because periodic voltage stability analysis is an inherent component of these monitoring requirements, particularly TOP-002-2.1b, Requirement R11, the standard drafting team did not propose to duplicate these requirements in proposed Reliability Standards VAR-001-4 and VAR-002-3. As noted above, the TOP Reliability Standards currently in development propose to carry forward the obligation

---

69 Order No. 693 at P 1875.

70 *Id*.

71 Reliability Standard TOP-002-2.1b, Requirement R10 provides that "[e]ach Balancing Authority and Transmission Operator shall plan to meet all [SOLs] and [IROLs]."

72 Reliability Standard TOP-002-2.1b, Requirement R11 provides that the "Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs." The requirement also specifies that the "Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator."

73 TOP-004-2, Requirement R6 provides that "Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including . . . [m]onitoring and controlling voltage levels and real and reactive power flows.

74 TOP-006-2, Requirement R2 requires that "[e]ach Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources."

to plan to meet and operate within SOLs and IROLs. Further, draft Reliability Standard TOP-002-4, Requirement R1 would require Transmission Operators to perform an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its SOLs.[75] An Operational Planning Analyses would include a voltage stability analysis to assist Real-time operations.

NERC is not proposing to modify its Reliability Standards to require that entities perform periodic voltage stability analyses using online techniques where commercially-available or offline simulation tools where online tools are not available. From a Reliability Standards perspective, the goal is to ensure that relevant entities perform periodic voltage stability analyses in a manner that helps maintain reliable operation in Real-time, not to limit or dictate the techniques or tools used to perform the analysis. An entity may perform the analysis using online techniques or offline simulation tools based on their availability and effectiveness. To comply with the TOP Reliability Standards, however, the entity must show that it performed a voltage stability analysis using techniques and/or tools designed to assess voltage stability effectively.

Controllable load: The Commission directed NERC to include controllable load as a reactive resource.[76] As noted above, proposed Reliability Standard VAR-001-4, Requirement R2 addresses this directive as controllable load is included as a "sufficient reactive resource."

---

[75] The term "Operational Planning Analysis" is proposed to be modified as follows:

> An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations.

[76] Order No. 693 at P 1879.

VAR-002 non-compliance window: The Commission directed NERC to consider modifying VAR-002 to add a time frame associated with an "incident" of non-compliance with VAR-002.[77] The standard drafting team considered modifications to VAR-002, but could not reach consensus on establishing, or developing guidelines for defining, a continent-wide time frame that would apply to all generators under VAR-002. Rather, the directive was addressed in an equally effective and efficient manner in proposed Reliability Standard VAR-001-4, Requirement R5, which requires that each Transmission Operator provide its Generator Operators with applicable voltage or Reactive Power schedules and notification requirements for deviations from those schedules. This approach provides the necessary flexibility to each Transmission Operator to define time frames based on its unique system assessments and tailor deviation notifications to the voltage constraints experienced in a particular area.

Technically sound voltage schedules: In Order No. 724, the Commission remanded to NERC an interpretation of VAR-001-1, Requirement R4 to ensure voltage schedules "reflect sound engineering, as well as operating judgment and experience."[78] To address this directive, Requirement R5, Part 5.3 requires a Transmission Operator, upon request, to provide the Generator Operator the technical support for how a voltage schedule and an associated tolerance band was established. This increased transparency will help ensure that the schedules reflect sound engineering and operating judgment.

D. Enforceability of the Proposed Reliability Standards

Proposed Reliability Standards VAR-001-4 and VAR-002-3 include VRFs and VSLs. The VRFs and VSLs guide how NERC will enforce the requirements of the proposed Reliability

---

[77] *Id*. at PP 1883, 1885.

[78] Order No. 724 at P 49.

Standards and comport with NERC and Commission guidelines related to their assignment. Exhibit E provides a detailed review of the VRFs and VSLs, as well as analysis on how the VRFs and VSLs were determined using the NERC and Commission guidelines.

The proposed Reliability Standards also include measures that support each requirement promulgated thereunder by clearly identifying what is required for compliance and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent and non-preferential manner and without prejudice to any party.[79]

V. EFFECTIVE DATE

As described in the Implementation Plan attached hereto as Exhibit B, NERC respectfully requests that the Commission approve proposed Reliability Standards VAR-001-4 and VAR-002-3 and the retirement of VAR-001-3 and VAR-002-2b, effective on the first day of the first calendar quarter after Commission approval. The proposed implementation period will provide sufficient time for responsible entities to develop or modify their processes to transition from compliance with existing Reliability Standards VAR-001-3 and VAR-002-2b to proposed Reliability Standards VAR-001-4 and VAR-002-3.

[79] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

VI. <u>CONCLUSION</u>

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- Proposed Reliability Standards VAR-001-4 and VAR-002-3 and the associated elements included in Exhibit A, effective as proposed herein;
- The proposed Implementation Plan included in Exhibit B; and
- The retirement of the currently effective Reliability Standards VAR-001-3 and VAR-002-2b, effective as proposed herein.

Respectfully submitted,

/s/ Shamai Elstein

Charles A. Berardesco
Senior Vice President and General Counsel
Holly A. Hawkins
Assistant General Counsel
Shamai Elstein
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, DC 20005
(202) 400-3000
charlie.berardesco@nerc.net
holly.hawkins@nerc.net
shamai.elstein@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: June 9, 2014

Exhibit A-1

Proposed Reliability Standard VAR-001-4

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4
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 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 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 Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational 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 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 instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. The Transmission Operator shall specify the criteria that will exempt generators from: 1) 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) 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 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 1 through 6 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 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 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 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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
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	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	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 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
	than 25% of the voltage schedules.	less than 50% of the voltage schedules.	the voltage schedules.	
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 #	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.

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.

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

~~A.~~ A. Introduction

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

2. **Number:** VAR-001-~~3~~4

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

4. **Applicability:**

   4.1. Transmission Operators~~.~~

   ~~**4.2.** Purchasing-Selling Entities.~~

   ~~**4.3.** Load Serving Entities.~~

   ~~**4.4.**~~**4.2.** Generator Operators within the Western Interconnection~~.~~ (for the WECC Variance)

5. ~~**(Proposed)**~~ **Effective Date:**~~-~~

   ~~**5.**~~**5.1.** The standard shall become effective on the first day of the first calendar quarter ~~six months~~ after the date that the standard is approved by an applicable ~~regulatory~~ governmental authority or as otherwise provided for in a jurisdiction where approval~~; or in those jurisdictions where no regulatory 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 ~~six months~~ after the date the standard is adopted by the NERC Board of ~~Trustees' adoption~~Trustees or as otherwise provided for in that jurisdiction.

~~B.~~ B. Requirements

~~Each Transmission Operator, individually~~ and ~~jointly~~Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with ~~other~~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 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~~, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring~~ 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.

~~**1.1.**~~ 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 ~~controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring~~adjacent Transmission Operators~~.~~

~~Each Transmission Operator shall acquire sufficient reactive resources – which~~ within 30 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~~ – within its area to protect the voltage levels under normal~~. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations,* and ~~Contingency conditions. This includes the~~ *Operational Planning]*

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

~~**R2.**~~**R3.** Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission ~~circuits.~~voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational 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 instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

~~**1.3.**~~ The Transmission Operator shall specify the criteria that ~~exempts~~will exempt generators from ~~compliance with the requirements defined in Requirement 4, and Requirement 6.1.~~

~~R3.1.~~R4. ~~Each Transmission Operator shall maintain a list of generators in its area that are exempt from~~ : 1) 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]*

~~R3.2.~~4.1 ~~For each~~If a Transmission Operator determines that a generator ~~that is on this~~has satisfied the exemption ~~list, the Transmission Operator~~criteria, it shall notify the associated Generator ~~Owner.~~ 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) 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 [1](which is either a range or a target value with an associated tolerance band) at either the ~~interconnection between~~high voltage side or low voltage side of the generator ~~facility and~~step-up transformer at the Transmission ~~Owner's facilities to be maintained by each generator.~~ Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~R4.~~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).

~~1.7. Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching;, and controllable load – to satisfy its reactive requirements identified by its Transmission Service Provider. (Retirement approved by FERC effective January 21, 2014.)~~

~~1.8.~~ The Transmission Operator shall ~~know the status of all transmission~~ provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power ~~resources, including the status of voltage regulators and power system stabilizers.~~

~~R6.1.~~5.2. ~~When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage~~ schedule ~~or its Reactive Power schedule.~~(which is either a range or a target value with an associated tolerance band).

~~1.10.~~ The Transmission Operator shall ~~be able to operate or direct~~provide the ~~operation of devices necessary to regulate transmission~~criteria used to develop voltage ~~and reactive flow.~~

~~R8.~~5.3. ~~Each Transmission~~schedules Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator ~~shall operate or~~

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

~~direct the operation of capacitive and inductive reactive resources within its area – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits~~within 30 days of receiving a request.

~~**1.0.** Each Transmission Operator shall maintain reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; and controllable load – to support its voltage under first Contingency conditions.~~

~~**2.0.** Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.~~

~~**3.0.** Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.~~

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.

~~**R11.**~~**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]*

~~**1.0.** The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.~~

~~B. Measures~~

~~**M3.** The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.~~

~~**M4.** The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.~~

~~**M5.** The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.~~

~~**M4.**~~**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 ~~Requirement 11~~the requirement and that it consulted with the Generator Owner.

~~C.~~ C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

~~Regional Entity.~~

~~**Compliance Monitoring Period and Reset Time Frame**~~

~~One calendar year.~~

~~**1.2. Compliance Monitoring and Enforcement Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**Data**~~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.

~~1.4.~~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 1 through ~~4~~6 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.

~~1.5.~~1.4. Additional Compliance Information:

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

~~**1. Violation Severity Levels (no changes)**~~

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operational 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 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 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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
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.~~ D. Regional Variances

~~Regional Variance for the Western Electricity Coordinating Council~~

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements ~~R3~~R4 and ~~R4.~~ R5. Please note that Requirement ~~R3~~R4 is deleted and ~~R4~~R5 is replaced with the following requirements.

Requirements

~~E.A.13.~~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.15.~~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.16.~~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.18.~~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.20.~~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.22.~~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.18.2.~~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.18.3.~~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.

Measures2

~~M.E.A.13.~~ 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.~~ 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.~~ 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

[2] 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.

voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

~~M.E.A.16.~~ 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.~~ 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.~~ 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.

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 #	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	he 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.	he 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.	T he 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.	he 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.A.1	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.	he 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	T he Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			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	/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.

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.

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

Exhibit A-2

Proposed Reliability Standard VAR-002-3

A. Introduction

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

2. **Number:** VAR-002-3

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**

   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, VAR-002-3 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. 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).

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

[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.
[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.

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.

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]*

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 transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						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.
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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						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, and 2.4.3.	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	8/16/2012	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. Adopted by Board of Trustees.	Revised
2b	4/16/2013	FERC Order issued approving VAR-002-2b	
3	5/7/2014	Adopted by the NERC Board of Trustees	

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:

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 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 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.

A. Introduction

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

2. **Number:** VAR-002-~~2b~~3

3. **Purpose:** To ensure generators provide reactive support and voltage control ~~necessary to ensure voltage levels, reactive flows, and reactive resources are maintained~~, within ~~applicable~~generating Facility ~~Ratings~~capabilities, in order to protect equipment and ~~the~~maintain reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Generator Operator~~.~~

   4.2. Generator Owner~~.~~

5. **Effective ~~Date:~~** ~~In those jurisdictions where regulatory approval is required, this~~**Dates**

   ~~**5.**~~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 ~~regulatory~~governmental authority is required for a standard to go into effect. Where approval ~~or as otherwise made effective pursuant to the laws~~by an applicable ~~to such ERO~~ governmental ~~authorities. In those jurisdictions where no regulatory approval~~authority is not required, ~~this standard~~ VAR-002-3 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 ~~approval~~or as otherwise provided for in that jurisdiction.

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] ~~or~~ 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 ~~the~~ automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up ~~or~~, 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).

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within ~~applicable Facility Ratings[4]) as directed by the Transmission Operator.~~ each generating Facility's capabilities[5]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or

---

[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.

[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 ~~establishing a tolerance band within which the target value is to be maintained during a specified period~~.

~~[4] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.~~

[5] 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.

Page 2 of 20

Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~R2.1.~~2.1. When a generator's ~~automatic voltage regulator~~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 ~~voltage and~~ reactive output to meet the voltage or Reactive Power schedule ~~directed~~provided by the Transmission Operator.

~~R2.2.~~2.2. When ~~directed~~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.

R3. Each Generator Operator shall notify its associated Transmission Operator ~~as soon as practical, but~~ of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of ~~any of the following:~~ 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]*

~~**3.1.** A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.~~

~~**3.2.** A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.~~

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]*

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.

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

~~**R4.1.**~~**5.1.** For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

~~**R4.1.1.**~~**5.1.1.** Tap settings.

~~**R4.1.2.**~~**5.1.2.** Available fixed tap ranges.

~~**R4.1.3.**~~**5.1.3.** Impedance data.

~~**4.1.4.** The +/- voltage range with step-change in % for load-tap changing transformers.~~

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

~~**R5.**~~**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: ~~Medium~~Lower] [Time Horizon: Real-time Operations]*

~~**R5.1.**~~**6.1.** If the Generator ~~Operator can't~~Owner cannot comply with the Transmission Operator's specifications, the Generator ~~Operator~~Owner shall notify the Transmission Operator and shall provide the technical justification.

~~**C. Measures**~~

Page 4 of 20

~~**M1.** The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator 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. Such evidence must 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.~~

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

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

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

~~**M5.** The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4~~

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

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

~~D.~~C. Compliance

1. Compliance Monitoring Process:

~~**1.1. Compliance Monitoring Responsibility**~~

1.1. ~~For entities that do not work for the Regional Entity, the Regional Entity shall serve as the~~ **Compliance Enforcement Authority**~~.~~**:**

~~For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the~~ 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. ~~Data~~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 Operator shall maintain evidence needed for Measure 1 through Measure 4 and Measure 7 for the current and previous calendar year.~~

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. ~~(Measures 5 and 6)~~ 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 ~~Enforcement~~Assessment Processes:

~~**The following processes may be used:**~~

~~**Compliance Audit**~~

~~**Self-Certification**~~

~~**Spot Checking**~~

~~**Compliance Investigation**~~

~~**Self-Reporting**~~

~~**Complaint**~~

"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

~~2. Violation Severity Levels~~

R # ~~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	~~The responsible entity~~ Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode ~~and failed to notify~~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.		
R2~~.~~	**Real-time Operations**	**Medium**	N/A	N/A	~~When directed~~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 ~~to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for~~	~~When directed~~The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator ~~to maintain the generator voltage or reactive power schedule~~and did not make the ~~Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes.~~ necessary notifications required by the Transmission Operator.	~~When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.~~	~~When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes.~~ ~~OR~~ ~~When a generator's automatic voltage regulator is out~~

R #	Time Horizon	VRF	Violation Severity Levels					
~~R #~~			Lower VSL	Moderate VSL	High VSL	Severe VSL		
					~~up to and including 45 minutes~~.	OR ~~When a generator's automatic voltage regulator is out of service, the~~ The Generator Operator ~~failed to~~did not have an operating AVR, and the responsible entity did not use an alternative method ~~to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator~~for controlling voltage. OR The Generator Operator ~~failed to~~did not modify voltage when directed, and the responsible entity did not provide ~~an~~any explanation ~~of why the~~		~~of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.~~

R #	Time Horizon	VRF	Violation Severity Levels					
~~R #~~			Lower VSL	Moderate VSL	High VSL	Severe VSL		
						~~voltage schedule could not be met~~.		
R3~~.~~	Real-time Operations	Medium	N/A	N/A	~~The Generator Operator failed to notify the Transmission Operator within 30 minutes of the information as specified in either R3.1 or R3.2~~N/A	The Generator Operator ~~failed to notify~~did not make the ~~Transmission Operator~~required notification within 30 minutes of the ~~information as specified in both R3.1 and R3.2~~status change.		
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.		
~~R4.~~R5	Real-time Operations	Lower	N/A	N/A	The ~~Responsible entity~~Generator Owner failed to provide ~~to~~ its associated Transmission Operator and Transmission Planner one of the types of data ~~as~~	The ~~Responsible entity~~Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data ~~as~~ specified in ~~R4~~Requirement R5	~~The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner three of the types of data as~~	~~The Responsible entity failed to provide to its associated Transmission Operator and Transmission Planner any of the types of data as~~

R #	Time Horizon	VRF	Violation Severity Levels				
~~R #~~			Lower VSL	Moderate VSL	High VSL	Severe VSL		
					specified in ~~R4~~Requirement R5 Parts 5.1.1 ~~or R 4~~, 5.1.2 ~~or 4~~, and 5.1.3 ~~or 4.1.4~~. ~~OR~~ ~~The information was provided in more than 30, but less than or equal to 35 calendar days of the request.~~	Parts 5.1.1 ~~or R 4~~, 5.1.2 ~~or 4~~, and 5.1.3 ~~or 4.1.4~~ ~~OR~~. ~~The~~ ~~information was provided in more than 35, but less than or equal to 40 calendar days of the request.~~	~~specified in R4.1.1 or R 4.1.2 or 4.1.3 or 4.1.4~~ ~~OR~~ ~~The information was provided in more than 40, but less than or equal to 45 calendar days of the request.~~	~~specified in R4.1.1 and R 4.1.2 and 4.1.3 and 4.1.4~~ ~~OR~~ ~~The information was provided in more than 45 calendar days of the request.~~
~~R5.~~R6	Real-time Operations	Lower	N/A	N/A	N/A	The ~~responsible entity failed to~~ Generator Owner did not ensure ~~that transformer~~ the tap ~~positions~~changes were ~~changed~~made according ~~to~~ the Transmission Operator's specifications. OR The ~~provided by~~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 ~~when said actions would not have violated safety, an equipment rating, a regulatory requirement, or a statutory requirement.~~ specifications.		
~~R5.1.~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity failed to notify the Transmission Operator and to provide~~			

R # ~~R #~~	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~technical justification.~~		

~~E.~~D. Regional ~~Differences~~Variances

None ~~identified~~.

E. Interpretations

None.

F. Associated Documents

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

None.

Version History

Version	Date	Action	Change Tracking
1	~~May 15,~~ 5/1/2006	Added "(R2)" to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	~~December~~ 12/19~~,~~ /2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	~~January~~ 1/16~~,~~ /2007	In Section A.2., Added "a" to end of standard number. Section F: added "1."; and added date.	Errata
1.1a	~~October~~ 10/29~~,~~ /2008	BOT adopted errata changes; updated version number to "1.1a"	Errata
1.1b	~~March~~ 3~~,~~ /3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	~~TBD~~8/16/2012	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. Adopted by Board of Trustees.	Revised
2b	~~August~~ 4/16~~,~~ ~~2012~~/2013	FERC Order issued approving VAR-002-2b~~Adopted by Board of Trustees~~	

~~2b~~3	~~April 16, 2013~~5/7/2014	Adopted by the NERC Board of Trustees~~FERC Order issued approving VAR-002-2b~~	

~~Appendix 1~~

~~Interpretation of Requirements R1 and R2~~

~~Request:~~

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

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

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

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

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

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

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

~~The material impact of misinterpretation of these standards is twofold.~~

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

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

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

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

~~**Interpretation:**~~

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

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

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

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

~~**Appendix 2**~~

~~**Interpretation of VAR-002-1a**~~

~~Request:~~

~~VAR-002 — Generator Operation for Maintaining Network Voltage Schedules, addresses the generator's provision of voltage and VAR control. Confusion exists in the industry and regions as to which requirements in this standard apply to Generator Operators that operate generators that do not have automatic voltage regulation capability.~~

~~The Standard's requirements do not identify the subset of generator operators that need to comply – forcing some generator operators that do not have any automatic voltage regulation capability to demonstrate how they complied with the requirements, even when they aren't physically able to comply with the requirements. Generator owners want clarification to verify that they are not expected to acquire AVR devices to comply with the requirements in this standard.~~

~~Many generators do not have automatic voltage regulators and do not receive voltage schedules. These entities are at a loss as to how to comply with these requirements and are expending resources attempting to demonstrate compliance with these requirements. A clarification will avoid challenges and potential litigation stemming from sanctions and penalties applied to entities that are being audited for compliance with this standard, but who do not fall within the scope or intent of the standard itself.~~

~~Please identify which requirements apply to generators that do not operate generators equipped with AVRs.~~

~~**Response:** All the requirements and associated subrequirements in VAR-002-1a apply to Generator Owners and Generator Operators that own or operate generators whether equipped with an automatic voltage regulator or not. The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. A generator that is not equipped with an automatic voltage regulator results in a functionally equivalent condition to a generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure.~~

~~There are no requirements in the standard that require a generator to have an automatic voltage regulator, nor are there any requirements for a Generator Owner to modify its generator to add an automatic voltage regulator. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.~~

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:

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 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 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

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001-4 and VAR-002-3

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 – All requirements 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, VAR-001-4 and VAR-002-3 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.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements, the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular jurisdiction in which the new standards are becoming effective.

Exhibit C

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how proposed Reliability Standards VAR-001-4 and VAR-002-3 have met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.**[2]

The proposed Reliability Standards achieve specific reliability goals. Proposed Reliability Standard VAR-001-4 (Voltage and Reactive Control) ensures that responsible entities monitor, control, and maintain voltage levels, reactive flows, and reactive resources in Real-time to protect equipment and maintain reliable operations. Proposed Reliability Standard VAR-002-3 (Generator Operation for Maintaining Network Voltage Schedules) ensures that responsible entities provide the reactive support and voltage control necessary to protect equipment and maintain reliable operations. Collectively, these proposed Reliability Standards are designed to prevent voltage instability and voltage collapse of the Bulk-Power System.

2. **Proposed Reliability Standards must be applicable only to users, owners, and operators of the Bulk-Power System, and must be clear and unambiguous as to what is required and who is required to comply.**[3]

Proposed Reliability Standard VAR-001-4 applies to Transmission Operators and, within the Western Interconnection, Generator Operators and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672.

---

[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs ¶ 31,212 (2006).

[2] Order No. 672 at PP 321, 324.

[3] *Id.* at PP 322, 325.

Proposed Reliability Standard VAR-001-4 contains six requirements that clearly and unambiguously state to whom each requirement applies and establishes the applicable entities' compliance obligations.

Proposed Reliability Standard VAR-002-3 applies to Generator Operators and Generator Owners and is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard VAR-002-3 contains six requirements that clearly and unambiguously state to whom each requirement applies and establishes the applicable entities' compliance obligations.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

Proposed Reliability Standards VAR-001-4 and VAR-002-3 include Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) that comport with NERC and Commission guidelines. As explained further in Exhibit F, the severity level assigned to each requirement (for a violation of the requirement) contains a clear explanation of the basis for the assignment, which promotes uniformity and consistency in applying each requirement. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.

Proposed Reliability Standards VAR-001-4 and VAR-002-3 also include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation. Upon approval by the Commission, the ranges of penalties for violations will be based on the applicable VRF and VSL in accordance with the sanctions table and the supporting penalty determination process described in the Commission-approved NERC Sanction Guidelines, Appendix 4B to the NERC Rules of Procedure.

[4] *Id.* at P 326.

4. A proposed Reliability Standard must identify a clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standards identify clear and objective criteria or measures for compliance, so that each Reliability Standard can be enforced in a consistent non-preferential manner. Specifically, each proposed Reliability Standard includes a clear statement of its purpose, the rationale behind each requirement, and a statement of the measures to be used in assessing compliance with each requirement. These provisions help provide clarity on how the requirements will be enforced, and ensure that the requirements will be assessed and enforced in a clear, consistent, and non-preferential manner, without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently – but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. Collectively, the proposed Reliability Standards improve reliability by ensuring that the Bulk-Power System operates at acceptable voltage levels and that sufficient Reactive Power on the Bulk-Power System exists to provide the voltage support necessary to maintain voltage stability. Proposed Reliability Standard VAR-001-4 improves reliability by requiring set system voltage schedules and voltage coordination among responsible entities. Proposed Reliability Standard VAR-002-3 improves reliability by requiring reactive support and voltage control from responsible entities necessary to protect equipment and maintain reliable operations. In each case, the proposed Reliability Standard provides flexibility to the responsible

[5] *Id.* at P 327.

[6] *Id.* at P 328.

entities to determine how best to achieve compliance, thereby ensuring reliability without imposing unduly burdensome costs or requiring the adoption of "best practices."

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, proposed Reliability Standards VAR-001-4 and VAR-002-3 represent a significant improvement over the previous versions as described herein.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[8]

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model. The existing regional variance in VAR-001-3 applicable in the Western Interconnection will continue to be enforced in proposed VAR-001-4.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[9]

The Proposed Reliability Standards do not cause undue negative effect on competition or restriction of the grid. Specifically, neither proposed Reliability Standard

[7] *Id.* at PP 329, 330.

[8] Order No. 672 at PP 331.

[9] *Id.* at P 332.

VAR-001-4 nor VAR-002-3 restricts the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The implementation time and proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the Reliability Standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing, or other relevant capability. The proposed effective dates will allow applicable entities adequate time to ensure compliance with the requirements and are explained in the proposed Implementation Plan, attached as Exhibit B.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. Exhibit F includes a summary of the Reliability Standards development proceedings, and details the processes followed to develop the proposed Standards.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all drafting team meetings were properly noticed and open to the public. Ballot initiatives achieved a quorum and exceeded the required ballot pool approval levels.

[10] *Id.* at P 333.

[11] *Id.* at P 334.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing vital public interests regarding the request for approval of proposed Reliability Standards VAR-001-4 and VAR-002-3. No comments were received indicating that the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other negative factors relevant to whether the proposed Reliability Standards satisfy the Commission's criteria for approval were identified.

---

[12] *Id.* at P 335.

[13] *Id.* at P 323.

Exhibit D-1

Mapping Document for Proposed Reliability Standard VAR-001-4

Project 2013-04 Voltage & Reactive Control

Mapping Document - Transition of VAR-001-3 to VAR-001-4

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3, Requirement R1	VAR-001-4, Requirement R1	Elements of VAR-001-3, Requirement R1 were duplicated in other Reliability Standards. Specifically, currently enforceable Reliability Standard TOP-004-2 Requirements R1, R2, and R3 duplicate monitoring and controlling voltage requirements. To comply with the obligation to operate within the IROLs and SOLs, entities must monitor and control voltage. Further, the Transmission Operations group of Reliability Standards is currently in development but will continue to include requirements that Transmission Operators ("TOPs"): (1) plan to operate within IROLs and SOLs; and (2) operate within IROLs and SOLs. Requirement R1 has been modified to remove the duplication and require the Transmission Operator ("TOPs") to specify a system voltage and Reactive Power schedules. A new part 1.1 has been added to allow for voltage coordination with adjacent TOPs and applicable Reliability Coordinators ("RCs").
VAR-001-3, Requirement R2	VAR-001-4, Requirement R2	The new Requirement R2 consolidates and modifies Requirements R2 and R9 of VAR-001-3 to require that TOPs schedule sufficient reactive resources. New Requirement R2 also clarifies the language with respect to the manner in which Transmission Operators may schedule sufficient reactive resources.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3, Requirement R3	VAR-001-4, Requirement R4	Requirement R4 carries forward the authority in currently enforceable Reliability Standard VAR-001-03, Requirement R3 for a TOP to exempt a Generator Operator ("GOP") from having to comply with all or some of its Reactive Power obligations. New Requirement R4, however, does not include a requirement for the TOP to maintain an exemption list. Instead, the standard focuses on the transparency of the exemption criteria and whether the TOP notifies the GOP if granted an exemption.
VAR-001-3, Requirement R4	VAR-001-4, Requirement R5	The new requirements have been updated to allow the TOP to provide the voltage or Reactive Power schedule at either the high side or the low side of the GSU. Also a tolerance band is now required under the new requirement. New parts have also been added to direct a GOP to operate in AVR, to require the TOP to provide notification requirements, and to provide the criteria for developing schedules and tolerance bands upon request.
VAR-001-3, Requirement R5	Deleted	The Federal Energy Regulatory Commission approved the retirement requirement as part of the Paragraph 81 project. *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, 145 FERC ¶ 61,147 at PP 25-26, Attachment A (2013).

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3, Requirement R6	Deleted	VAR-001-3, Requirement R6 was deleted because it was duplicative of existing TOP Reliability standards (i.e., TOP-006-2, Requirement R1), which require knowing the status of Reactive Power resources. The TOP standards currently in development would carry forward this obligation. Although power system stabilizers are not specifically named in the TOP standards, the areas that rely on PSS equipment will require monitoring the PSS status under the data specifications of the TOP standards.
VAR-001-3, Requirement R7	VAR-001-4, Requirement R3	VAR-001-4, Requirement R3 carries forward the obligation from VAR-001-3, Requirement R7
VAR-001-3, Requirement R8	VAR-001-4, Requirement R3	The standard drafting team concluded that there was no need to separately carry forward VAR-001-3, Requirement R8 because it was subsumed in proposed VAR-001-4, Requirement R3.
VAR-001-3, Requirement R9	VAR-001-4, Requirement R2	See comments for Requirement R2.
VAR-001-3, Requirement R10	Deleted	VAR-001-3, Requirement R10 was deleted because it was duplicative of existing TOP Reliability standards (i.e., TOP-004-2, Requirements R1 and R4), which require TOPs to correct SOL/IROL violations resulting from reactive resources deficiencies. The TOP standards currently in development would carry forward this obligation.
VAR-001-3, Requirement R11	VAR-001-4, Requirement R6	The requirement has been updated to allow for scheduling consultation.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3, Requirement R12	Deleted	VAR-001-3, Requirement R10 was deleted because it was duplicative of existing TOP and EOP Reliability standards (i.e., TOP-004-2; EOP-003-2), to take corrective action, including load-shedding, to prevent voltage collapse. The TOP standards currently in development would carry forward this obligation.

Exhibit D-2

Mapping Document for Proposed Reliability Standard VAR-002-3

Project 2013-04 Voltage & Reactive Control

Mapping Document - Transition of VAR-002-2b to VAR-002-3

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, Requirement R1	VAR-002-3, Requirement R1	VAR-002-3, Requirement R1 carries forward the obligation in currently effective VAR-002-2b, Requirement R1 for Generator Operators (“GOPs”) to operate generators in automatic voltage control mode but modifies the requirement to allow a GOP to operate in a different control mode if instructed by the Transmission Operator (“TOP”). New Requirement R1 also adds testing as a time when a generator need not operate in automatic voltage control mode or a different mode instructed by the Transmission Operator.
VAR-002-2b, Requirement R2	VAR-002-3, Requirement R2	VAR-002-3, Requirement R2 carries forward the affirmative obligation from VAR-003-1, Requirement R2 that the GOP maintain the voltage or Reactive Power schedule provided by the TOP pursuant to VAR-001-4, Requirement R5, unless the TOP exempts the GOP from doing so pursuant to VAR-001-4, Requirement R4. New Requirement R2 also adds that the GOP need not comply with the schedule if it satisfies the notification requirements for deviations established by the TOP VAR-001-4, Requirement R5, Part 5.2. Lastly, new Requirement R2 includes a provision to allow GOPs that do not monitor voltage at the location specified in their voltage schedule provided by the TOP to convert the schedule to the voltage point monitored by the GOP.

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, Requirement R3	VAR-002-3, Requirement R3 and R4.	Proposed Requirements R3 and R4 separate the notification requirements in currently-effective VAR-002-2b, Requirement R3 into two requirements: (1) for AVR/PSS status changes (proposed Requirement R3), and (2) for reactive capability changes (proposed Requirement R4). Each of the proposed requirements provides for a 30-minute window to allow a GOPs time to resolve an issue before having to notify the TOP of a change.
VAR-002-2b, Requirement R3	VAR-002-3, Requirement R5	VAR-002-3, Requirement R5 carries forward the obligations in VAR-002-2b, Requirement R3 but modifies it to the sub-part that requires the GOP to provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." The measure was also modified to add that a GOP must provide the data "within 30 calendar days"
VAR-002-2b, Requirement R4	VAR-002-3, Requirement R6	VAR-002-3, Requirement R6 modifies VAR-002-2b, Requirement R4 only to apply to the same functional entity throughout the requirement.

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.   A copy of the standard with the associated VRFs and VSLs is available here.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the

Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification – VAR-002-3 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is necessary because this requirement could affect the stability of the BES, but the requirement itself addresses instances where a GOP will not necessarily operate in with the AVR in different control modes or when the TOP will instruct a GOP to operate in other modes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP control modes are not as critical because the TOP is monitoring the system. The companion requirement to VAR-002-3 (in VAR-001-4) are properly designated with a HIGH VRF to ensure voltage schedules are provided as part of the TOPs plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be the same VRFs for VAR-001-4 Requirement R5. VAR-001-4 Requirement R5 requires the TOP to specify a schedule and notification requirements that the GOP must follow.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a GOP not operating in the proper control mode can affect the BES, but a single violation is unlikely to lead to instability, separation, or cascading failure. This is especially the case since a TOP will also be monitoring for voltage deviations.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guideline, this VSL acknowledges the criticality of this requirement and whether or not a system voltage schedule was created.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL because this requirement only has a "severe" VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirements.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R2 focuses on GOPs maintaining a schedule, but there could be system events that will pull a GOP out of schedule. Also, late at night and early in the morning, the system may experience instances of low or high voltage. This could impact the BES, but a single instance is unlikely to lead to instability, separation, or cascading failure. The sub-requirements also require the GOP to modify the voltage schedule when directed by the TOP.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report lists Reactive Power and voltage control as critical areas where a violation could severely affect the reliability of the Bulk-Power System, there are general times when a GOP will be unable to maintain a voltage schedule due to system condition. These instances occur frequently during the early morning and late at night. The companion requirement to VAR-002-3 (in VAR-001-4) are properly designated

	with a HIGH VRF to ensure voltage schedules are provided as part of the TOP's plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement, including all sub-parts.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be the same VRFs for VAR-001-4 Requirement R5. VAR-001-4 Requirement R5 requires the TOP to specify a schedule and notification requirements that the GOP must follow.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a GOP not maintaining a schedule can affect the BES, but a single violation is unlikely to lead to instability, separation, or cascading failures. This is especially the case since a TOP will also be monitoring for voltage deviations
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

the Current Level of Compliance	
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation,	The proposed VSL is not based on cumulative number of violations.

Not on A Cumulative Number of Violations	

VRF Justification – VAR-002-3 Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement warrants a Medium VRF and is consistent with the NERC definition because this requirement is whether the GOP made the required notifications to the TOP within the appropriate timeframes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP notifications are unlikely to lead to system instability, separation, or cascading failures. This is particularly the case because the TOP is still operating the system to stay within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This VRF is drafted to be consistent with other standards (e.g., BAL) that address making appropriate notifications.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not making the appropriate notifications can impact the grid, but the TOPs are still effectively monitoring the system; thus, instability, separation, or cascading failures are unlikely due to a single violation.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-002-3 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the standard is violated only when a notification is not made to the TOP; therefore, a severe VSL is warranted. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement warrants a Medium VRF and is consistent with the NERC definition because this requirement is whether the GOP made the required notifications to the TOP within the appropriate timeframes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP notifications are unlikely to lead to system instability, separation, or cascading failures. This is particularly the case because the TOP is still operating the system to stay within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This VRF is drafted to be consistent with other standards (e.g., BAL) that address making appropriate notifications.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not making the appropriate notifications can impact the grid, but the TOPs are still effectively monitoring the system; thus, instability, separation, or cascading failures are unlikely due to a single violation.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-002-3 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the standard is violated only when a notification is not made to the TOP; therefore, a severe VSL is warranted.

"Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is a Lower VRF because the tap setting data does not change frequently, and a violation is not expected adversely affect the BES.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement would not adversely impact the BES

	if violated. The tap information is provided during interconnection, and it is not expected to change frequently. Therefore, a Lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The parts within Requirement R5 are consistent with Requirement R5 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: There are no other standards that address Tap settings.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation is similar to an administrative violation. Further, since tap settings are infrequently changed, a violation would not adversely impact the BES.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R5	
NERC VSL Guidelines	Consistent with NERC’s VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

the Current Level of Compliance	
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation,	The proposed VSL is not based on cumulative number of violations.

Not on A Cumulative Number of Violations	

VRF Justification – VAR-002-3 Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is a Lower VRF because the tap setting data does not change frequently, and a violation is not expected adversely affect the BES.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement would not adversely impact the BES if violated. The tap information is provided during interconnection, and it is not expected to change frequently. If a violation were to occur, the system would still operate at the level prior to making any tap setting changes. Therefore, a Lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The part within Requirement R6 is consistent with Requirement R6 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: There are no other standards that address Tap settings.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation is similar to an administrative violation. Further, since tap settings are infrequently changed, a violation would not adversely impact the BES.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the requirement focuses on whether tap changes were made. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

Exhibit F

Summary of Development History and Record of Development

Project 2013-04 Voltage & Reactive Control

Related Files

Status:

The NERC Board of Trustees adopted VAR-002-3 on May 7, 2014. The standard will be filed for regulatory approval.

Background:

When the first versions of the VAR standards were approved in FERC Order No. 693,[1] the Commission also issued several directives with regard to how to improve the standard. Each of the outstanding directives are explained in detail in the technical white paper (see project page).

The informal consensus building for VAR began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, remove paragraph 81 candidates, and implement results-based approaches. A discussion of the ad hoc group's consensus building and collaborative activities are also included in the technical white paper.

Based on stakeholder outreach, the VAR-001 and VAR-002 standards have been modified. The proposed VAR-001 answers most of the FERC directives from Order No. 693, and VAR-002 has been modified to address certain compliance issues today. This posting is soliciting comment on a pro forma standard and a Standard Authorization Request (SAR).

---

[1] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Draft	Action	Dates	Results	Consideration of Comments
VAR-002-3 Clean (72)|Redline to last posted (73) Implementation Plan Clean (74) |Redline to last posted (75) Supporting Materials: Compliance Input (76) Mapping Document Clean (77)|Redline to last posted (78) Draft Reliability Standard Audit Worksheet VAR-002-3 (79) VRF and VSL Justifications (80)	Final Ballot Info (81) Vote>>	04/24/14 - 05/05/14	Summary (82) Ballot Results (83)	
VAR-002-3 Clean (56) |Redline to last posted (57) Implementation Plan Clean (58) |Redline to last posted (59)	Additional Ballot and Non-binding Poll Info (66) Vote>>	04/04/14 – 04/14/14 (Extended in order to achieve quorum) (Closed)	Summary (68) Ballot Results (69) Non-Binding Poll Results (70)	

Supporting Materials: Unofficial Comment Form (Word) (60) Compliance Input (61) Mapping Document Clean (62) |Redline to last posted (63) Draft Reliability Standard Audit Worksheet VAR-002-3 (64) VRF and VSL Justifications (65)	Comment Period Info (67) Submit Comments>>	02/27/14 - 04/14/14		Consideration of Comments (71)
VAR-001-4 Clean (42)|Redline to last posted (43) Implementation Plan Clean (44) |Redline to last posted (45) Supporting Materials: Compliance Input (46) Mapping Document Clean (47) |Redline to last posted (48) Draft Reliability Standard Audit Worksheet VAR-001-4 (49) VRF/VSL Justifications (50) Consideration of Issues and Directives (51)	Final Ballot Updated Info (52) Info (53) Vote>>	12/13/13 - 12/23/13 (Revised) (closed)	Summary (54) Ballot Results (55)	
VAR-001-4 Clean (20) |Redline to last posted (21) VAR-002-3 Clean (22) |Redline to last posted (23) Implementation Plan Clean (24)|Redline to last posted (25)	Additional Ballots and Non-binding Polls Updated Info (32) Info (33) Vote>>	11/15/13 – 11/26/13 Extended 1 additional day, closing 11/26/13. (closed)	Summary (35) Ballot Results: VAR-001-4 (36) VAR-002-3 (37)	

<table>
<tr>
<td rowspan="2">Supporting Materials:

Unofficial Comment Form (Word) (26)

Compliance Input (27)

Mapping Document Clean (28) |Redline to last posted (29)
Draft Reliability Standard Audit Worksheet
VAR-001-4 (30)
VAR-002-3 (31)</td>
<td></td>
<td></td>
<td>Non-Binding Poll:

VAR-001-4 (38)

VAR-002-3 (39)</td>
<td></td>
</tr>
<tr>
<td>Comment Period

Info (34)

Submit Comments>></td>
<td>10/11/13 – 11/25/13

(closed)</td>
<td>Comments Received (40)</td>
<td>Consideration of Comments (41)</td>
</tr>
<tr>
<td rowspan="4">Draft Standard
VAR-001-4 (1)

VAR-002-3 (2)

Implementation Plan(3)

Standard Authorization Request (4)

Supporting Materials:
Unofficial Comment Form (Word) (5)

Technical White Paper (6)

Mapping Document (7)

Compliance Input (8)

Proposed Timeline for the Formal Development (9)</td>
<td>VAR-001-4 and VAR-002-3

Ballot and Non-binding Poll
Updated Info (10)

Vote>></td>
<td>08/23/13 - 09/03/13

Extended 1 additional day, closing 9/4/13.

(closed)</td>
<td>Summary (14)

Ballot Results (15)

Non-binding Poll Results (16)</td>
<td rowspan="4">Consideration of Comments for VAR-002-3 (18)

Consideration of Comments (19)</td>
</tr>
<tr>
<td>Comment Period
Info (11)
Submit Comments>></td>
<td>07/19/13 - 09/03/13

Extended 1 additional day, closing 9/4/13.

(closed)</td>
<td>Comments Received (17)</td>
</tr>
<tr>
<td>Join Ballot Pool>></td>
<td>07/19/13 - 08/19/13

(closed)</td>
<td rowspan="2"></td>
</tr>
<tr>
<td>Info (12)
Submit Nomination>>

Unofficial Nomination Form (13)</td>
<td>07/24/13 - 08/02/13

(closed)</td>
</tr>
</table>

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment on July 19, 2013

Description of Current Draft

This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.

Anticipated Actions	Anticipated Date
SAR Authorized by the Standards Committee	July
45 Day SAR Comment and Initial Ballot Open	July
Nomination Period Opens	July
Standard Drafting Team Appointed	July
Initial Comment and Initial Ballot Closes	August
Final Ballot Opens	October
Final Ballot Closes	October
BOT Adoption	November
Filing to Applicable Regulatory Authorities	December

Effective Dates

In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

Version History

Version	Date	Action	Change Tracking
1	6/18/2007	Initial Standard is FERC approved	
2	1/10/2011	FERC approved added LSEs and Controllable Load to the standard.	
3	6/20/2013	WECC Variance is approved by FERC	

Definitions of Terms Used in the Standard

None.

Introduction

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

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

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. Reliability Coordinators

   4.3. Generator Operators within the Western Interconnection

Requirements and Measures

Rationale for R1: This requirement will allow each Transmission Operator (TOP) to establish its own policies and procedures, and the criteria for periodic updates will be individualized based on the stability of each TOP's regions. The language is refined to show that coordination with neighboring TOPs is required. It also states TOP shall provide data to the Reliability Coordinator (RC) for its monitoring functions to respond to address the FERC directive in P 1855 of Order No. 693, which directed NERC to add RC monitoring to the VAR standards. P 1868 requires NERC to add more "detailed and definitive requirements to include more detailed and definitive requirements on “established limits” and “sufficient reactive resources” and identify acceptable margins (i.e. voltage and/or reactive power margins)."

R1. Each Transmission Operator shall have documented policies or procedures that are implemented to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits as defined below. *[Violation Risk Factor: High] [Time Horizon: Operations]*

1.1. These documented policies or procedures shall include criteria used in system assessments. The criteria for the assessments shall include established steady-state limits, voltage stability limits and associated operating margins, and voltage schedules along with associated tolerance bands.

1.2. Each Transmission Operator shall provide a copy of these documented policies or procedures to adjacent Transmission Operators.

1.3. Each Transmission Operator shall provide a copy of these documented policies or procedures to its Reliability Coordinator.

M1. The Transmission Operator shall have evidence of documented policies or procedures as specified in Requirement 1. As stated in R1, the policies and procedures must detail how criteria for steady-state and voltage stability limits are used in the Transmission Operator’s assessments of the system. In order to demonstrate the Transmission Operator is implementing the policies or procedures, the Transmission Operator must be able to provide evidence that proves voltage is currently being monitored. Such evidence may include, but is not limited to: 1) proof that points are telemetered, 2) alarms are functioning, and 3) during events of low or high voltage the policies and procedures are being followed to respond to control voltage levels. The Transmission Operator must also provide evidence that the policies or procedures were communicated to adjacent Transmission Operators and to its Reliability Coordinator. Evidence may include, but is not limited to, emails, website postings, and meeting minutes. Simply posting a copy of the policies or procedure on a public website is not sufficient if the Transmission Operator and Reliability Coordinator were not notified as to where to find the policies or procedures.

Rationale for R2:

P 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically. The informal ad hoc group and industry participants concluded that the best models and tools are the ones that have been proven over time, and that the requirement should not require any utility to purchase new online simulations tools. Therefore, the new requirement does not specify when to use online tools. The sub-requirements detail the real-time and day-ahead assessments necessary under R1. The existing VAR-001 also requires a list of sufficient reactive resources; this was retained in the proposed requirement as FERC determined in a letter order that this list answered the directive in P 1868 to detail the list of "sufficient reactive resources." Controllable load is specifically included to answer FERC's directive in P 1879.

R2. Each Transmission Operator and Reliability Coordinator shall perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations]*

2.1. Each Transmission Operator shall operate or direct the real-time operation of devices necessary to regulate transmission voltage and reactive flow necessary to regulate transmission voltage and reactive flow which may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding, to maintain system voltages within established limits.

2.2. As a result of the assessments, each Transmission Operator shall ensure that sufficient reactive resources have been scheduled to meet acceptable day-ahead voltage limits identified in Requirement R1. Sufficient reactive resources may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; and controllable load.

M2. Each Transmission Operator and Reliability Coordinator shall have evidence of current or past studies used to schedule sufficient reactive resources. Each Transmission Operator shall also provide proof that additional resources were scheduled when necessary. During a real-time event where voltage must be adjusted, a Transmission Operator shall show evidence to show directions were given to adjust the operation of capacitive and inductive resources. This may include directions to Generator Operators to operate within new tolerance bands or to make manual adjustments if necessary. Transmission Operators shall also have evidence to show proof of directing new resources to come online. Those resources can include, but is not limited to capacitor banks, switching, adjusting controllable load, and when necessary load can be shed. For the day-ahead scheduling, Transmission Operators shall provide copies of provide day-ahead studies used to schedule enough resources to meet expected voltage requirements.

Rationale for R3:

These exemptions offer TOPs the option to exempt certain generators during maintenance or system events when those units are not able to maintain voltage schedules. Sub-requirements containing an exemption list were removed from the existing standard because this created more compliance issues with regard to how often the list would be updated and maintained.

R3. The Transmission Operator shall specify the criteria that will exempt generators from compliance with the requirements defined in Requirement 4 and any associated notification requirements. *[Violation Risk Factor: Lower] [Time Horizon: Operations]*

3.1. In the event a Transmission Operator approves a generator as satisfying the criteria, it shall notify the associated Generator Operator.

M3. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions. The Transmission Operator shall also have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3. Temporary exemptions maybe provided to generators during scenarios where notifications/communications are not necessary due to a system event that prevents a Generator Operator from maintaining a schedule. Similarly, when an Automatic Voltage Regulator (AVR) is malfunctioning, which prevents a Generator Operator from maintaining a voltage schedule and tolerance band, temporary exemptions may be provided. For temporary exemptions, evidence showing the exemptions were granted must be provided. If the exemptions were given verbally from the Transmission Operator, the phone recordings or emails commemorating the phone call must be provided. For temporary exemptions, the evidence of communication must also include the timeframe for how long the exemption will last.

Rationale for R4:

The new requirement adds “tolerance band” in order to provide more detailed information when establishing limits.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band (at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion) at the interconnection point between the generator facility and the Transmission Owner's facilities to be maintained by each generator. *[Violation Risk Factor: Medium] [Time Horizon: Operations]*

4.1. The Transmission Operator shall provide the voltage or Reactive Power schedule and 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).

M4. The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule and tolerance band as specified in Requirement 4 to the applicable Generator Operators. For real-time directives, evidence may include recorded phone logs.

Rationale for R5:

Since power system stabilizers (PSS) equipment is not highlighted in any other standard, the VAR standard is the appropriate place to ensure the equipment is being monitored. This requirement is not duplicative of the TOP standards because the voltage regulators and power system stabilizer are highlighted.

R5. The Transmission Operator shall know the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. *[Violation Risk Factor: Medium] [Time Horizon: Operations]*

M5. The Transmission Operator shall have evidence to show Reactive Power resources are being monitored. Evidence may include, but is not limited to screen shots of EMS/SCADA data, alarms, and phone logs. In the event the monitoring system does not work, each Transmission Operator should have a protocol in place to show these resources are being monitored.

Rationale for R6:

Although tap settings are first established at 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.

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

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.

Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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**	**High**	The Transmission Operator has documented criteria for assessments, but has provided a copy to only one of the parties that should have received a copy (either a neighboring TOPs or its RC).	The Transmission Operator has documented policies and procedures, but has not provided copies to either the neighboring TOPs or its RC.	The Transmission Operator has documented policies or procedures, but none of the sub-requirements were followed.	The Transmission Operator has no documented policies or procedures.
R2	**Operations**	**High**	N/A	The Transmission Operator only performs day-ahead assessments and only schedules day-ahead resources.	N/A	The Transmission Operator does not perform assessments and therefore does not have policies and procedures implemented to have sufficient Mvars. A lack of real-time operations is also severe.
R3	**Operations Planning**	**Lower**	N/A	N/A	N/A	The Transmission Operator does not have exemption criteria.
R4	**Operations**	**Medium**	N/A	N/A	The Transmission Operator provides voltage or Reactive Power schedules to only some of the GOPs.	The Transmission Operator does not provide voltage or Reactive Power schedules and tolerance bands at all.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations**	**Lower**	N/A	The Transmission Operator is unaware of the status in a stable area.	The Transmission Operator does not know the status of important equipment in weaker areas that were identified in assessments as part of R1.	N/A
R6	**Operations**	**Lower**	Either the technical justification or timeframe are not provided.	Neither the technical justification nor the timeframe are provided.	N/A	N/A

Regional Variances

Regional Variance for the Western Electricity Coordinating Council from VAR-001-3 is retained.

Interpretations

None.

Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please see the VAR White Paper for further technical information.

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment on July XX, 2013

Description of Current Draft

This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.

Anticipated Actions	Anticipated Date
SAR Authorized by the Standards Committee	July
45 Day SAR Comment and Initial Ballot Open	July
Nomination Period Opens	July
Standard Drafting Team Appointed	July
Initial Comment and Initial Ballot Closes	August
Final Ballot Opens	October
Final Ballot Closes	October
BOT Adoption	November
Filing to Applicable Regulatory Authorities	December

Effective Dates

In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

None.

Introduction

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

Requirements and Measures

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 voltage controlling mode. The measure has been updated include some of the evidence that can be used for Compliance purposes.

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) unless 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] or shutdown[2] 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 the automatic voltage control mode for a reason other than start-up or shutdown.

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. If a generator is being started up or shut down with the automatic voltage control off and no notification of the automatic voltage regulator 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. Such evidence must 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.

---

[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.

Rationale for R2:

R2 details how a Generator Operator (GOP) operates the system to a maintain voltage schedule and when the GOP is expected to notify the Transmission Operator (TOP). Sub-requirement 2.1 provides guidance on a non-compliance window in the event a unit is deviating from schedule, and the GOP must notify the TOP if it is unable to return to schedule. Thus, the non-compliance window allows for notifications when a unit is unable to provide additional VAR support (e.g., when hitting an operational limit) or when the unit is too small to raise voltage. In both instances, the TOP may then provide some type of temporary exemption as outlined in VAR-001.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[3] (within applicable Facility Ratings[4]) as directed by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

2.1. If a GOP drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator within 15 minutes when both of the following conditions are met: 1) the GOP is operating outside of the prescribed voltage or Reactive Power schedule tolerance band[5] for 15 minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule.

2.2. When a generator's automatic voltage regulator is out-of-service, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

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

M2. Generator Operators will still make all attempts to operate within the tolerance bands provided by the TOP, but natural drifting may occur. In instances where there is an event occurring to pull a unit out of the tolerance band, the Generator Operator will not be held in non-compliance with this requirement if the sub-requirements 2.1, 2.2, and 2.3 are met. In order to identify when a unit is deviating from its schedule, GOPs will monitor voltage based on existing equipment at its facility. Therefore, GOPs have the option to operate on a voltage schedule on either the high-side or convert the high-side schedule to a low-side schedule at the GOP's discretion. For units that monitor on the low-side/terminal voltage, Generator Operators shall provide evidence of the method of conversion from the high-side schedule to low-side monitoring. For sub-requirement 2.1, most units will not be able to return to schedule due to a limiting factor. Such limiting factors may include, but are not limited to: 1) terminal voltage, 2) bus voltage, 3) equipment temperature,

[3] The voltage or Reactive Power schedule is a target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period.

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

[5] GOPs monitor and control voltage based on their equipment limitations. GOPs will monitor their voltage or Reactive Power schedule tolerance bands either at the high-side or low-side/terminal voltage.

4) transformer, 5) auxiliary equipment, 6) Volts/Hz limits, and 7) excitation or regulator limits. GOP shall have evidence to show compliance with requirement R2 by providing 1) Communications with the TOP when the Generator Operator was operating outside of the prescribed voltage or Reactive Power schedule tolerance band for 30 minutes or less (the 30 minutes allow for 15 minutes to call and 15 minutes to be outside of the tolerance band) AND Generator Operator is no longer able to return to its voltage or Reactive Power schedule; 2) Generator Operator implemented an alternative method to control reactive output when the AVR was out-of-service or unavailable; 3) compliance with directive to modify voltage or a notification that the directive could not be met. Evidence may include, but is not limited to Generator Operator logs, SCADA data, phone logs, and any other alarming notifications that would alert the Transmission Operator that both conditions were met. Timing for Requirement R2.1 is crucial, and Generator Operators are expected to begin timing an event as soon as the unit is operating outside of the tolerance band. Further, voltage documentation during a system event maybe requested by an auditor to show measures were taken to bring the unit back into schedule.

Rationale for R3:

This requirement has been modified to reduce the number of violations for when an AVR goes out-of-service and then comes back in-service. Fifteen (15) minutes have been built into the requirement to allow a Generator Operator time to resolve an issue before having to notify the Transmission Operator of a status or capability change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. The 15-minute window should resolve most issues, and further trouble-shooting will probably be required if the status change is unresolved within 15 minutes.

R3. Each Generator Operator shall notify its associated Transmission Operator of a status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability within 30 minutes of the change. If the status has been restored within the first 15 minutes of such change, then there is no need to call the TOP. *[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 of the changes identified in Requirement 3. If the status has been restored within the first 15 minutes, no call is necessary; therefore, if a status on Reactive Power resource has changed, and that change lasts greater than 15 minutes, the GOP must notify its associated TOP within 30 minutes of when the change first occurred.

Rationale for R4:

This requirement and corresponding measure language has been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

R4. 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]*

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

4.1.1. Tap settings.

4.1.2. Available fixed tap ranges.

4.1.3. Impedance data.

M4. The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.3.

Rationale for R5:

This requirement and corresponding measure language has been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations].*

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

M5. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means 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:

As defined in the NERC Rules of Procedure, "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	The responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The responsible entity did not perform any of the sub-requirements.
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The responsible entity did not make the notification within 30 minutes.
R4	**Real-time Operations**	**Lower**	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.	When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes. OR When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. OR The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.		generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to provide an explanation of why the voltage schedule could not be met.
R5	**Real-time Operations**	**Lower**	N/A	N/A	N/A	The GOP failed to perform the tap changes, and the GOP did not provide technical justification for why it cannot comply with the TOP directive

Regional Variances

None.

Interpretations

None.

Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please see the VAR White Paper for further technical information.

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001 and VAR-002

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators

Generator Owners

Transmission Operators

Reliability Coordinators

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 - In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires a documented policy or procedure for assessments; the Transmission Operators need a quarter to prepare documentation. Also for Transmission Operators that do not provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular Jurisdiction in which the new standards are becoming effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Voltage and Reactive Control; Generator Operation for Maintaining Network Voltage Schedules		
Date Submitted:	July 18, 2013		
SAR Requester Information			
Name:	Soo Jin Kim		
Organization:	NERC		
Telephone:	404-446-9742	E-mail:	soo.jin.kim@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives from FERC Order No. 693 and improve upon the existing VAR standards.
Purpose or Goal (How does this request propose to address the problem described above?):
The pro forma standard consolidates the reliability components of the existing VAR-001 standard, adds new requirements to address FERC's directives in Order No. 693, and provides a non-compliance window in VAR-002 notification requirements.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objectives are to address the outstanding directives from FERC Order 693 and added a non-compliance window for when a GOP must notifiy a TOP when a unit is deviating from a voltage schedule.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
• The drafting team will answer the outstanding VAR directives from FERC Order No. 693. The VAR-001 directives are summarized from P 1880 of Order No. 693 as: ○ Expand the applicability to include reliability coordinators and LSEs; ○ Include detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins above the voltage instability points; ○ Include Requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available, to assist real-time operations, for areas susceptible to voltage instability; ○ Include controllable load among the reactive resources to satisfy reactive Requirements; and ○ Address the power factor range at the interface between LSEs and the transmission grid. • The VAR-002 directive is to simply consider adding more detail around what would constitute an incident of non-compliance for a Generator. • The drafting team will also modify the VAR-002 standard in order to address some of the numerous notifications that are required by the currently enforceable standard.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Attachment (pro forma VAR standards) and White Paper of this SAR submittal package.

Reliability Functions

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling	Purchases or sells energy, capacity, and necessary reliability-related

Reliability Functions		
	Entity	services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to	Yes

Reliability and Market Interface Principles	
access commercially non-sensitive information that is required for compliance with reliability standards.	

Related Standards	
Standard No.	Explanation
VAR-001- 3	Voltage and Reactive Control
VAR-002-2b	Generator Operation for Maintaining Network Voltage Schedules

Related SARs	
SAR ID	Explanation
Project 2008-01	Voltage and Reactive Planning and Control

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None

Regional Variances	
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	VAR-001-3 WECC variance is retained.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2013-04 Voltage and Reactive Control (VAR) Revisions

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft VAR-001-4 and VAR-002-3 standards. The electronic comment form must be completed by 8:00 p.m. ET by **Tuesday, September 3, 2013**.

If you have questions please contact Soo Jin Kim via email or by telephone at 404-446-9742.

The project page may be accessed by clicking here.

Background Information

When the first versions of the VAR standards were approved in FERC Order No. 693,[1] the Commission also issued FERC issued several directives with regard to how to improve the standard. Each of the outstanding directives are explained in detail in the technical white paper (see project page).

The informal consensus building for VAR began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, remove paragraph 81 candidates, and implement results-based approaches. A discussion of the ad hoc group's consensus building and collaborative activities are also included in the technical white paper.

Based on stakeholder outreach, the VAR-001 and VAR-002 standards have been modified. The proposed VAR-001 answers most of the FERC directives from Order No. 693, and VAR-002 has been modified to address certain compliance issues today. This posting is soliciting comment on a pro forma standard and a Standard Authorization Request (SAR).

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

---

[1] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

NERC

Question

1. Do you have any specific questions or comments relating to the scope of the proposed pro forma standard or SAR?

☐ Yes
☐ No

Comments:

2. Do you have any specific questions or comments relating to the requirements in the proposed pro forma standards?

☐ Yes
☐ No

Comments:

3. Do you have any issues with the proposed timeframes for the notification requirements in VAR-002 R2 and R3? If you propose different timeframes, please explain how a change in the timeframe will not create a reliability gap?

☐ Yes
☐ No

Comments:

4. During outreach, several issues pertaining to voltage coordination were discussed, as outlined in the 'minority issues' section of the technical white paper. However, those issues are not addressed because such issues are outside of the scope of this project. What suggestions do you have for improving voltage coordination between TOPs and GOPs? Is it appropriate to address this issue in a Standards project?

Comments:

NERC

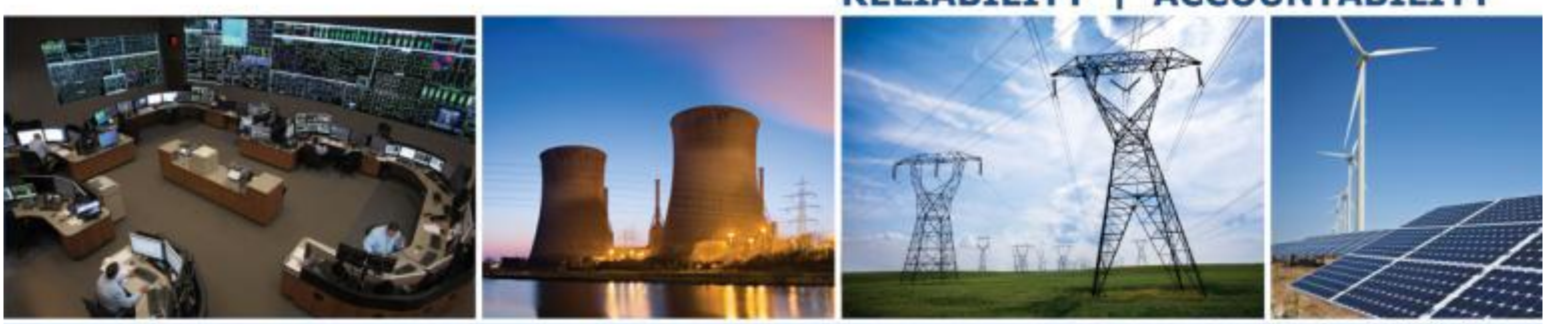
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

White Paper on the VAR Standards

VAR-001 and VAR-002

July 18, 2013

RELIABILITY | ACCOUNTABILITY



3353 Peachtree Road N
Suite 600, North Tow
Atlanta, GA 3032
404-446-2560 | www.nerc.co

Table of Contents

Executive Summary

The VAR Reliability Standards provide the minimum requirements for maintaining voltage stability on the bulk-power system. The industry considers VAR-001 to represent transmission requirements for monitoring the reactive power performance of the system, and VAR-002 represents generator obligations for voltage support. When the VAR standards were initially approved by the Federal Energy Regulatory Commission ("FERC" or the "Commission") in 2006, the Commission provided several directives on how to improve the VAR standards. NERC initiated Project 2008-01 to address these FERC directives, but that project was unable to be completed due to a project reprioritization. Project 2008-01 and its Standard Authorization Request (SAR) used a prescriptive approach to address the FERC directives, and that project also contemplated adding an additional planning standard. This project took a different approach by implementing the Paragraph 81[1] and results-based standards initiatives. This project also utilized the recommendations from a panel of Independent Experts' Review of the NERC Reliability Standards. Due to this variance in approach, the informal development group is presenting a new SAR to post for industry comment.

In summary, FERC gave the following directives to modify VAR-001:

- Expand the applicability to include Reliability Coordinators (RCs) and load-serving entities (LSEs).
- Include detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins above the voltage instability points.
- To assist real-time operations for areas susceptible to voltage instability, include requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available.
- Include controllable load among the reactive resources to satisfy reactive requirements.
- Address the power factor range at the interface between LSEs and the transmission grid.

FERC directed NERC to consider modifying VAR-002 to require more detailed and definitive requirements when defining the time frame associated with an "incident" of noncompliance. Hence, FERC directed NERC to consider a timeframe for allowing a generator to be out of schedule before having to make a notification to its TOP.

In early 2013, NERC initiated an informal development project to address the directives, and an informal development group was formed from industry subject matter experts, NERC staff, and staff from FERC's Office of Electric Regulation. The informal development group sought to answer FERC's directives and improve some of the compliance issues that exist today for the VAR standards. The informal development group drafted several pro forma versions of the VAR standard and sought broad industry feedback through individual phone conversations, conference calls, technical conferences, and webinars.

Since 2006, many changes have occurred that impact the VAR standards. Several new standards have been drafted and approved in the last seven years. Also, FERC recently issued a Notice of Proposed Rulemaking (NOPR) addressing Paragraph 81, and that NOPR recommends retiring certain VAR requirements that are redundant with Open-Access Transmission Tariffs (OATTs). In addition, VAR-002 has consistently been identified as one of the most violated standards, so certain compliance issues surround VAR-002 had to be addressed.

In concert with the Paragraph 81 initiative, each of the above-mentioned directives does not equate to a new VAR requirement. Instead, the informal development group removed certain redundancies with other standards and created requirements that provide for documented policies and procedures to address the above directives for VAR-001.

The pro forma VAR-001 has added RC monitoring requirements, and the standard requires each Transmission Operator (TOP) to have written operating policies and procedures used to define voltage limits. Those policies and procedures must set definitive guidelines on the frequency of system assessments. Further, the pro forma standard states that controllable load is a viable reactive power resource that can be used in the day-ahead and real-time operations. The informal development project did not address power factor, because the relevant requirement that currently addresses LSEs and

[1] *See North American Electric Reliability Corp.*, 138 FERC ¶ 61,193, at P 81, *order on reh'g and clarification*, 139 FERC ¶ 61,168 (2012).

power factor is proposed for retirement by FERC in its June 2013 NOPR on Paragraph 81 because the OATT covers the arrangement for ancillary services that include VAR purchases to maintain power factor.

Additionally, VAR-002 has been amended in the pro forma standard to provide for a noncompliance timeframe when a generator is out of voltage schedule and when reactive power equipment is out-of-service and then back in-service status again. The language not only addresses FERC’s directive, but it also provides resolution to several compliance issues in existence today. Certain timing elements for VAR-002 may be debated during the formal development process, but the informal development group has reached a consensus on the principles of providing these time periods.

As detailed further below, the informal development group drafted the pro forma VAR standard in a manner that would accomplish three objectives: 1) address the FERC directives; 2) mitigate compliance issues for generators in VAR-002; and 3) simplify the TOP’s requirements in VAR-001 while maintaining reliability and eliminating nuisance phone calls. The pro forma standard is not overly prescriptive, and Compliance has prepared guidance that will develop into RSAWs and auditor training. This guidance will allow for more predictability when the new VAR standard is implemented, and it will hopefully alleviate some industry concerns regarding future audits.

Purpose

The purpose of this white paper is to provide a summary of the issues, rationale, and support for the proposed revisions to the currently enforceable VAR standards, VAR-001 and VAR-002. This white paper also provides an explanation of how outstanding VAR directives from the Commission contained in Order No. 693[2] are addressed going forward. This white paper is a product of the informal development process, which provides for the formation of an informal development group. The informal development group met several times and conducted numerous webinars and technical conferences from February through June 2013. The information obtained through industry outreach was discussed thoroughly by the informal development group, and several of the discussion topics are reflected throughout this paper. In addition, the contents of this paper will give a foundation to the formal development process.

The ultimate goal of the Standards team is present the new VAR standards to the Board of Trustees in their November 2013 meeting. Thus, the formal Standards Drafting Team will be seeking final industry approval of the VAR standards by October 2013.

[2] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

History of the VAR Informal Development

The informal development group started with a group of individuals that were originally part of Project 2008-01. Due to a project reprioritization conducted by the Standards Committee and NERC, Project 2008-01 was halted. There is some overlap between the current VAR project and project 2008-01, but the scope is slightly different. Project 2008-01 was moving toward creating a VAR planning standard in addition to modifying VAR-001 and VAR-002. The current project is only amending VAR-001 and VAR-002, and the current project remains predominantly focused on addressing the outstanding FERC directives.

The informal development group first met on a February 15, 2013 conference call. The meeting was to introduce the various parties and a coordinate logistics for the informal development process. The informal development group is currently comprised of the following:

- Dennis Chastain – Tennessee Valley Authority
- Bill Harm – PJM Interconnection L.L.C.
- Steve Hitchens – Bonneville Power Administration
- Sharma Kolluri – Entergy Services Inc.
- Martin Kaufman – ExxonMobil Research and Engineering Company
- Joshua Pierce – Southern Company
- Hari Singh – Xcel Energy
- Hamid Zakery – Calpine Corporation
- Scott Berry – Indiana Municipal Power Agency

Members of the informal development group met in person on February 27 and 28 in Atlanta. The group then convened several times over conference calls before an April 11 webinar.

The April 11 webinar was the first time the group proposed new VAR language to address a majority of the directives from Order No. 693. The industry provided significant feedback during two subsequent technical conferences. The first technical conference was hosted by Southern Company in Atlanta, Georgia, on April 18, 2013. The second technical conference was held at Xcel Energy in Denver, Colorado, on April 29, 2013. Both conferences provided an opportunity for the informal development group to listen to industry concerns regarding the VAR standards, and the informal development group answered numerous questions on the current draft of the pro forma standards.

The informal development group reconvened for a two-day meeting at Entergy on May 15, 2013. The group also invited several individuals who participated in the webinars and technical conferences to attend the meeting. During the May meeting, the VAR pro forma standard was modified several times. The informal development group continued the discussion on how to best address industry's concerns through electronic communications and several conference calls.

The next iteration of the pro forma standard was then presented to the industry on a June 14 webinar. The webinar contained several survey questions, and the informal development group was able to gauge whether a majority of industry supported the pro forma standard. Based on the survey and webinar feedback, the informal development group was able to amend the pro forma standard further before presenting the final draft to the Standards Committee on July 18, 2013.

Technical Discussion

Background

What is Reactive Power?

Reactive power does not have the same characteristics as real power. Real power is measured in watts and able to be transmitted over long distances. Real power is an energy supply that is eventually distributed to end-use customers. Reactive power is just as important as real power because it is necessary to maintain system stability. Reactive power supports voltage. Voltage is measured in volts, and electrical current is measured in amperes. Reactive power is measured in volt-amperes reactive (VARs). When the Bulk Electric System (BES) does not have enough reactive power, there is risk of a voltage collapse, which could lead to cascading outages. In fact, a lack of reactive power supply was a contributing factor to the large blackouts in 2003 and 2011.

Nature of Reactive Power and Why it is Necessary

Generally reactive power is needed to provide voltage support and maintain system stability. Prabha Kundur, a leading subject matter expert in system stability, explains, "[p]ower system stability may be broadly defined as that property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance."[3] The VAR standards ensure that there is enough reactive power on the system to provide the voltage support necessary to avoid voltage collapse. Although there are numerous reactive power resources, the best and largest source of reactive power or VAR support comes from generators. However, the amount of reactive power that a generator can create is proportional to the amount of MWs being produced. Therefore, the more VARs produced at a generating facility, the fewer MWs produced.

VAR-001

The stated purpose of the VAR-001 standard is 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. The VAR standards focus on the Operations horizon (which is real-time up to one year into the future). The informal development group is cognizant of the fact that the nature of reactive power on the network varies depending on local conditions. Thus, the group focused on the process that the requirements would detail, not the proper numbers a TOP should enforce in the standard. For VAR-001, the group would not put operational limits on how a TOP should manage voltage stability for its regions; more specifically, the informal development group did not want to place numerical requirements on what the proper operational limits should be for the continent. Operating margins vary due to specific system characteristics as well as the operating conditions. Rather than detailing a continent-wide back-off margin, the informal development group designed the pro forma VAR-001 to require the Transmission Operator to document policies and procedures used to establish, monitor, and control voltage and reactive power flows (Mvars). Those policies are then used to establish voltage and reactive power schedules for the generators.

Requirement R1

R1 requires that documented policies and procedures are in place. These policies and procedures must include criteria for the assessments of the TOP's systems. The policies will consequently include studies used to establish voltage schedules and associated tolerance bands. In addition, the system assessments must include dynamic voltage limits and operating margins. By requiring a documented policy and procedure, the reliability standard removes the opportunity for auditors or other parties to scrutinize a TOP's own system studies.

R1 also requires Transmission Operators to communicate their policies and procedures with their associated RC and neighboring TOPs. This type of communication relates to R2, which details how a TOP and RC take a system study and ensure sufficient reactive power is available to support both real-time and day-ahead operations.

Requirement R2

[3] Prabha Kundur, *Power System Stability and Control,* Electric Power Research Institute, p. 17 (1994).

R2 requires both TOPs and RCs to perform system assessments in order to schedule reactive resources for both the real-time and day-ahead time frames. By scheduling sufficient reactive resources, the TOP and RC are maintaining voltage levels (and consequently system stability) under both normal and contingency situation. R2 further defines "sufficient reactive resources," and those resources include controllable load pursuant to FERC Order No. 693.

Requirement R3

R3 requires each TOP to specify what criteria will exempt a generator from 1) having to follow a provided voltage schedule; or 2) providing a notification under VAR-002. The TOP must notify the generator when an exemption is given, but there are no requirements on what the criteria should be for exemptions. This enables TOPs to have flexibility when providing exemptions during maintenance or system events. For example, if a unit is experiencing a malfunction in AVR equipment, the TOP may provide a temporary exemption to the generator until the equipment is repaired.

Requirement R4

R4 requires each TOP to specify a voltage or reactive power schedule and associated tolerance band for each generator. By requiring both a tolerance band and a documented policy or procedure for establishing voltage schedules, there is a level of transparency as to how voltage or reactive power schedules were created. The informal development group refrained from providing any language that requires GOPs to mutually agree with TOPs on specific numbers. Such language could create disputes between the parties as to what the appropriate voltage schedule should be for a unit. To preserve a TOP's ability to assess and monitor its system, and in an effort not to undermine the TOP standards, R4 provides more transparency while clearly maintaining a TOP's role in determining voltage schedules.

Requirement R5

R5 ensures that the TOP knows the status of all reactive power resources, automatic voltage regulators, and power system stabilizers in its system. This requirement mandates that the TOP actively monitor the system for voltage issues, and the new measure language now specifies that electronically metered points and EMS data will serve as a compliance mechanism for this particular requirement.

Requirement R6

The informal development group did not modify the requirement regarding step-up transformer tap changes.

WECC Variance

FERC approved the WECC variance to VAR-001 on June 20, 2013.[4] The WECC variance eliminates the TOP's ability to allow for exemptions, and it also requires a TOP to (1) issue a choice of voltage schedules for each of the generating resources that are on-line and part of the BES in its area; (2) provide to Generator Operators (GOPs) a voltage schedule reference point; and (3) provide transmission equipment data and operating data requested by GOPs to support their set point conversion methodology.[5] The informal development group did not adopt the WECC variance because it is more stringent than the existing standard, and numerous TOPs want the flexibility to allow for exemptions from notification requirements, particularly when maintenance is being performed or when a generator's AVR is malfunctioning. However, the current pro forma standard does not affect the WECC variance. Since the WECC variance is retained, the VAR-001 standard is applicable to GOPs in the WECC region.

VAR-002

The purpose behind the VAR-002 standard is for generators to provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the interconnection. Currently, VAR-002 is problematic due the numerous violations for GOPs 1) when a unit deviates from schedule; and 2) when an AVR turns on, then off. In both instances, a generator has an obligation under the currently enforceable standard to call a TOP within 30 minutes. The current standard does not allow for any deviations from notification requirements; thus, the GOP must determine if it is more appropriate to make a notification or address a potential issue that is affecting the voltage schedule or AVR status. The notifications themselves also create "nuisance" phone calls for TOPs. Most TOPs have the ability to monitor voltage through telemeter equipment.

[4] *See Petition for Approval of Proposed Reliability Standard VAR-001-3 (WECC Variance)*, Letter Order, Docket No. RD13-6-000 (issued June 20, 2013).

[5] *See* VAR-001-3

Thus, most TOPs already know when a unit drifts out of schedule. In order to address both the compliance issues and FERC's directive to consider a noncompliance window, the pro forma VAR-002 proposes language that gives a GOP time to respond to an issue before notifying its TOP.

Requirement R2

R2 requires GOPs to follow a TOP-provided voltage or reactive power schedule. However, there is universal agreement among TOPs and GOPs that if a unit drifts out of schedule momentarily and then drifts back into schedule, there is no risk to the reliability of the system. However, under the current VAR-002 standard in effect, when a unit drifts out of schedule there is an obligation to notify the TOP. Also, when the unit goes back into schedule there is an obligation to notify the TOP again. Thus, for a slight deviation, a GOP may face two potential violations for failure to make notifications to the TOP.

Based on industry feedback, a TOP should be notified when a unit cannot follow a voltage schedule. However, notifications for every schedule change are harmful to reliability because such calls detract focus from addressing system issues as they occur. The new language in the pro forma standard for R2 requires a GOP to notify a TOP when 1) the unit has been out of schedule for 15 minutes; AND 2) when a unit cannot return to schedule. In most cases, a unit will not be able to return to schedule when it has encountered an operating limit. There are also instances when a system event is pulling the unit out of schedule, and the unit is too small to move its voltage back in schedule. In these situations, it is important for the TOP to be notified, because those units cannot provide anymore voltage support to combat a system event.

Requirement R3

R3 requires a GOP to notify its TOP within 30 minutes of a "status" change. The status change identifies whether a reactive resource is available for voltage support. In an effort to allow GOP to first identify and address why a status change has occurred, the new pro forma standard Requirement R3 gives the GOP an initial 15 minutes to correct and restore the status of any reactive power resource. However, if the status has not been corrected after 15 minutes, the GOP has 15 minutes to notify its associated TOP of the status change.

Requirements R1, R4, and R5

The informal development group did not modify the requirement regarding AVR and tap changes.

Monitoring

Both R2 and R3 inherently have several compliance issues with regard to how voltage is monitored and controlled. Most TOPs provide GOPs with a voltage schedule as the high side of the generator step-up transformer, but a large number of GOPs only have metering equipment on the low side of the transformer. Therefore, in order to meet a voltage schedule, but these GOPs will convert the "high-side" schedule to a "low-side" schedule. The low-side schedule is then usually translated into an AVR control point or target. However, for several smaller facilities and nuclear facilities, those generators have installed metering on the high-side. Also, some facilities have made additions to their facilities to add load-drop compensation to see monitoring on the high-side. Thus, although many Generators monitor voltage on the low side of the terminal, there are a significant number of facilities that monitor voltage on the high side. Generators that use high-side voltage reference for regulation receive voltage reference signals from their associated TOP. This can create an issue during audits, because the standard does not dictate which method is acceptable for monitoring voltage.

In order to develop a continent-wide standard that allows GOPs to monitor voltage based on existing equipment limitations, the language of pro forma VAR-002's measures was greatly augmented. Specifically, the GOPs were explicitly given the discretion to monitor on either the high side or low side of the transformer. The pertinent language added to M2 is, "[i]n order to identify when a unit is deviating from its schedule, GOPs will monitor voltage based on existing equipment at its facility. Therefore, GOPs have the option to operate on a voltage schedule on the high side or convert the high-side schedule to a low-side schedule at the GOP's discretion." This language is necessary to assure GOPs that the standard will not determine where specific equipment should be installed at a facility. Further, this language clarifies to an auditor that either high-side or low-side monitoring is sufficient for VAR-002 compliance.

AVR

Once the AVR is set and in "voltage controlling" mode, the AVR should automatically adjust to voltage swings. At issue is whether a generator is required to make any adjustments to a control-point or AVR setting when the AVR response is not enough to react to a voltage deviation or system event. There is a current debate in the industry as to what actions are required to maintain system stability. From the Generator's perspective, the AVR is the best mechanism to address voltage, and several Generators advocate that if an AVR setting should be adjusted, then the respective TOP should direct that AVR change. The TOPs argue that if an event is occurring, there is not enough time to call each generator to dictate the specifications for an adjustment; further, the TOPs assert that generators have an obligation to maintain a voltage schedule that includes making the necessary AVR adjustments. This industry divide is not addressed in the pro forma standard presented today. The informal development group did not address changing underlying principles of the VAR-002 standard, because the scope of the project with regard to VAR-002 was merely to consider a non-compliance window. However, the issue may be revisited during the formal development stage by the standard development team.

Minority Issue on Voltage Coordination

Another issue that arose during the informal outreach was the need for more voltage coordination between GOPs and TOPs. Some GOPs advocated for VAR standards to be re-written in order require more coordination, but again since the scope of this project is to focus on FERC directives, the informal development group opted to require more detail on how the TOPs study their systems. This issue will be presented for comment during the balloting of the pro forma, and the formal drafting team will make recommendations based on comments received as to how to address this issue in the future.

Outstanding FERC Directives

The VAR standards were first approved in FERC Order No. 693.[6] However, in approving the standards, the Commission also gave several directives on how to improve the VAR standards for reliability purposes. VAR-001 targets the transmission responsibilities for maintaining voltage stability while VAR-002 focuses on generator functions. Order No. 693 summarized the directives for VAR-001 as requiring NERC to do the following:

> (1) expand the applicability to include RCs and LSEs; (2) include detailed and definitive requirements on "established limits" and "sufficient reactive resources" as discussed above, and identify acceptable margins above the voltage instability points; (3) to assist real-time operations for areas susceptible to voltage instability include requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available; (4) include controllable load among the reactive resources to satisfy reactive requirements; and (5) address the power factor range at the interface between LSEs and the transmission grid.[7]

For VAR-002, FERC directed NERC to consider providing more definitive requirements on what a noncompliance window should be for mandatory notifications. Each of the relevant directives is explained in further detail below.

Directive from P 1855 of Order No. 693

"Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities."

VAR Informal Consideration

The informal development group amended VAR-001 to make RCs applicable to this standard, and requirements were added that identify RC monitoring for voltage stability. The informal development group did not expand the VAR standards to be overly prescriptive with regard to how an RC should monitor its own system; further, the group did not want to duplicate the efforts of the IRO standards pending before FERC. Instead the group focused on the most critical elements necessary for an RC to monitor its system for voltage stability. An RC performs many monitoring functions, but for voltage stability it is necessary to ensure that 1) the RC is aware of how its TOPs are monitoring voltage, and 2) the RC is performing the adequate studies to ensure reactive resources are properly scheduled for both real-time and day-ahead operations. Although some entities in Texas provided feedback that certain RCs perform functions equivalent to a TOP, the informal development group did not expand VAR-001 to give parity to TOPs and RCs. Upon further investigation, these situations are addressed through contractual obligations that clearly outline the reliability roles of both parties. The new RC functions are reflected in the new VAR pro forma standard through requirements R1 and R2. Both requirements are detailed further below.

Directive from P 1858 of Order No. 693

"The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities."

VAR Informal Consideration

This FERC directive was addressed in VAR-001-2.[8] The Commission also recently issued a NOPR regarding Paragraph 81 that recommended retiring the existing VAR requirement that initially answered FERC's directive in P 1858.[9] FERC's support for Paragraph 81 and rationale for proposing the retirement is:

[6] *See generally,* Order No. 693 at PP 1846-1885.
[7] Order No. 693 at P 1880.
[8] *See* FERC letter order, *NERC Petition for Approval of Proposed Modifications to Reliability Standards BAL-002-1; EOP-002-3; FAC-002-1; MOD-021-2; PRC-004-2; and VAR-001-2,* 134 FERC ¶ 61,015 (2011).
[9] *See Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards,* Notice of Proposed Rulemaking, 143 FERC ¶ 61,251 (2013) ("NOPR").

> We propose to approve the retirement of VAR-001-2, Requirement R5 based on NERC's assertion that Requirement R5 is redundant with provisions of the *pro forma* OATT. Specifically, Schedule 2 of the open access transmission tariff requires transmission providers to provide reactive power resources, either directly or indirectly, and requires transmission customers to either purchase or self-supply reactive power resources.[10]

In light of this NOPR, the informal development group is not adding new language to the VAR standard that would address this directive. Further, there is an ongoing NERC effort to evaluate if purchasing-selling entities (PSEs) should continue to be a registered function. The informal development group may address this directive in the future, pending a final rulemaking from FERC and a determination on the status of the future applicability of standards to PSEs.

Directive from P 1861 of Order No. 693

"In the NOPR, the Commission asked for comments on acceptable ranges of net power factor at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions... The Commission believes that Reliability Standard VAR-001-1 is an appropriate place for the ERO to take steps to address these concerns by setting out requirements for transmission owners and LSEs to maintain an appropriate power factor range at their interface. **We direct the ERO to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk- Power System."**

VAR Informal Consideration

Initially, the informal development group addressed the directive on power factor in two ways. First, based on P 1863,[11] the informal development group considered requiring seasonal power factor data to be provided to the TOPs on request. This would ensure the system studies were based on accurate data. Second, the informal development group considered whether entities could ensure power factor is maintained by arranging for VARs when MWs are purchased. However, the recently issued NOPR recommends retiring the requirement that currently requires VARs to be acquired due to redundancy with OATT. The NOPR also recommends withdrawing P 1863 as a directive because the Commission clarified the paragraph to be general guidance, not a FERC directive to modify the standard.[12]

In addition, the informal development group did not further amend the pro forma standard to add obligations to maintain power factors, because the FAC-001 standard requires Transmission Owners (TOs) to set interconnection requirements including "Voltage, Reactive Power, and **power factor control**."[13] Interconnection agreements also define minimum power factor requirements as a contractual obligation.[14] In an effort to keep the VAR standard consistent with interconnection requirements established by contract, and consistent with the pro forma Generator Interconnection agreements pursuant to FERC Order No. 2003 which requires a 0.95 leading to 0.95 lagging power factor,[15] the informal group did not add any additional requirements at this time to address power factor.

Directive from P 1862 of Order No. 693

"We direct the ERO to include APPA's concern in the Reliability Standards development process. We note that transmission operators currently have access to data through their energy management systems to determine a range of

---

[10] NOPR at P 83.

[11] Order No. 693 at P 1863 (stating "[t]he Commission expects that the appropriate power factor range developed for the interface between the bulk electric system and the LSE from VAR-001-1 would be used as an input to the transmission and operations planning Reliability Standards").

[12] *See* NOPR at Attachment A.

[13] *See* FAC-001-0, R 2.1.9. (available at: http://www.nerc.com/files/FAC-001-0.pdf) (emphasis added).

[14] *See, e.g., Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), order on reh'g, Order No. 2003- A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. &Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008) (*establishing Large Generator Interconnection Agreement requirement).

[15] Order No. 2003 at P 542 (finding "[w]e adopt the power factor requirement of 0.95 leading to 0.95 lagging because it is a common practice in some NERC regions. If a Transmission Provider wants to adopt a different power factor requirement, Final Rule LGIA Article 9.6.1 permits it to do so as long as the power factor requirement applies to all generators on a comparable basis").

power factors at which load operates during various conditions, and **we suggest that the ERO use this type of data as a starting point for developing this modification."**

VAR Informal Consideration

APPA stated, "It may be difficult to reach an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors. APPA further states that system power factors will be affected by the transmission infrastructure used to supply the load."[16] APPA's concerns were discussed, and the informal development group did not want to establish a particular range on power factor, especially since power factor requirements are detailed in interconnection agreements as discussed with the P 1861 directive.

Directive from P 1868 of Order No. 693

"In the NOPR, the Commission expressed concern that the technical requirements containing terms such as "established limits" or "sufficient reactive resources" are not definitive enough to address voltage instability and ensure reliable operations. To address this concern, the NOPR proposed directing the ERO to modify VAR-001-1 to include more detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. **We will keep this direction, and direct the ERO to include this modification in this Reliability Standard**."

Directive from P 1869 of Order No. 693

We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for "established limits" and "sufficient reactive resources." **Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process.** The Commission believes that the concerns of Dynegy, EEI and MISO are best addressed by the ERO in the Reliability Standards development process.

VAR Informal Consideration for PP 1868 and 1869.

In an effort to address this directive and in order to preserve the TOs' flexibility to monitor their systems accordingly, the informal development group added requirements in the pro forma standard VAR-001 Requirement R1 that require steady-state and voltage limits to be included in the criteria used to assess transmission systems:

> R1. Each Transmission Operator shall have documented policies or procedures that are implemented to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits as defined below:
>
>> R. 1.1. These documented policies or procedures shall include criteria used in system assessments. The criteria for the assessments shall include established steady-state and voltage stability limits with associated tolerance bands and operating margins.

Also, a new Requirement R2 was updated to include existing language on reactive resources that a TOP can schedule in both the real-time and day-ahead time frame. That list of sufficient reactive resources includes reactive generation scheduling, transmission line and reactive resource switching, and controllable load.

Directive from P 1875 of Order No. 693

In response to the concerns of APPA, SDG&E and EEI on the availability of tools, the Commission recognizes that transient voltage stability analysis is often conducted as an offline study, and that steady-state voltage stability analysis can be done online. The Commission clarifies that it does not wish to require anyone to use tools that are not validated for real-time operations. Taking these comments into consideration, the Commission clarifies its proposed modification from the NOPR. For the Final Rule, **we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time**

[16] Order No. 693 at P 1860.

operations. The ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.

VAR Informal Consideration
The informal group determined that the Commission is not requiring TOPs to purchase new online models or to implement tools that will not adequately study a TOP's reactive power requirements. Instead, the group allowed the TOPs to create their own documented procedures for performing assessments in pro forma standard Requirement R1.

Further, TOPs may under the new pro forma standard align their voltage planning with the pending TPL standards currently being reviewed by the Commission. The TPL standards require voltage studies, as outlined below:

> **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady-state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [17]

Directive from P 1879 of Order No. 693

The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1. **While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.**

VAR Informal Consideration
NERC addressed this directive in a prior version of the VAR standard,[18] but as mentioned above, the list for sufficient reactive resources that includes controllable load has been retained in R2.

Directive from P 1885 of Order No. 693

"Dynegy has suggested an improvement to Reliability Standard VAR-002-1, and NERC should consider this in its Reliability Standards development process."

Dynegy requested that VAR-002 be modified to include "more detailed and definitive requirements when defining the time frame associated with an 'incident'of non compliance."[19]

VAR Informal Consideration
The informal development team addressed this directive in two separate requirements. The noncompliance incidences at issue occur 1) when a generator deviates from a voltage or reactive power schedule; and 2) when a generator is not operating a unit in automatic voltage control mode; more specifically, automatic voltage regulator (AVR) should be in service and controlling voltage.

The new pro forma VAR-002 R2.1 addresses when a unit must notify its TOP when a unit is out of schedule:

> R.2.1. If a GOP drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator within 15 minutes when both of the following conditions are met: 1) the GOP is operating outside of the prescribed voltage or

[17] *See*TPL-001-2, R5 (available at http://www.nerc.com/files/TPL-001-2.pdf).
[18] *See NERC Petition for Approval of Proposed Modifications to Reliability Standards BAL-002-1; EOP-002-3; FAC-002-1; MOD-021-2; PRC-004-2; and VAR-001-2,* 134 FERC ¶ 61,015 (2011).
[19] Order No. 693 at P 1883.

> Reactive Power schedule tolerance band[20] for 15 minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule.

The new pro forma VAR-002 R3 addresses when a unit must contact its TOP when the facility is out of AVR:

> R3. Each Generator Operator shall notify its associated Transmission Operator of a status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability within 30 minutes of the change. If the status has been restored within the first 15 minutes of such change, then there is no need to call TOP.

The informal development group established the 15-minute time requirements following much discussion. Several industry stakeholders advocated for a larger window of time before a notification must be made; however, there is no consensus on when a reliability gap would be created by expanding the time requirements. Some stakeholders also argued that 15 minutes was excessive.

[20] GOPs monitor and control voltage based on their equipment limitations. GOPs will monitor their voltage or Reactive Power schedule tolerance bands either at the high-side or low-side/terminal voltage.

Conclusion

The goal of the VAR informal development project is to provide a venue for addressing many of the issues that can arise during the formal development process. By engaging with industry stakeholders through an active dialogue, the informal development group was able to efficiently address the concerns of many entities through conference calls, webinars, and informal group meetings. The informal group collaborated over the past five months to develop robust pro forma VAR standards that will serve as the basis for a new VAR standard, which should be posted for industry comment in August 2013. This white paper serves to memorialize some of the discussions surrounding contentious VAR issues, and it provides a basis for the technical discussion that occurred during the informal process. For the aforementioned discussion, the informal development group recommends approval of the accompanying SAR and the posting of the pro forma standards in order to continue the progress on the VAR standards.

Entity Participants

Appendix B: Entity Participants

The below entities represent a non-exhaustive list of entities that had personnel that participated in the VAR informal development effort in some manner, which may include one of the following: direct participation on the ad-hoc group, inclusion on the wider distribution (the "plus" list), attendance at workshops or other technical discussions, participation in a webinar or teleconference, or by providing feedback to the group through a variety of methods (e.g., email, phone calls, etc.). Additionally, though not listed here, announcements were distributed to wider NERC distribution lists to provide the opportunity for entities that were not actively participating to join the effort.

Table 2: Entity Participation in VAR Informal Development

AES	DTE Energy	ISO-NE	Pepco Holdings	TECO Energy
Alcoa	Duke	ITC Transmission	PGE	Tenaska
Ameren	Dynegy	KCP&L	PGN	Texas MPA
Arizona Public Service	Edison Mission Generation	Luminant	PJM	Tri-State G&T
ATC	EDPR	MEAG	PNM	TVA
Austin Energy	Enervision	MidAmerican Energy	PPL	WAPA
BGE	Entegra power	Midwest ISO	PSC	WE Energies
Black Hills Corporation	Entergy	MN Power	PSE	WFEC
Bonneville Power Admin.	Entergy Fossil & Hydro	National Grid	PSEG	WICF
BP	epelectric	NCEMC	Rayburn Electric	Wisconsin Public Service
Calpine	ERCOT	NERC	San Francisco PU	Xcel Energy
CenterPoint Energy	Essential Power LLC	NextEra	SCANA	**Regional Entities:**
City of Tallahassee	Exelon Corp	NiSource	SCE	FRCC
Colorado Springs Utilities	ExxonMobil	Northeast Utilities	Seminole electric	MRO
ComEd	FERC	Nova Scotia Power	Siemens	NPCC
ConEd	FPL	NPPD	SMUD	RFC
Constellation	Garland Power & Light	NYISO	Snohomish County PUD	SERC
Constellation Energy Nuclear Group (CENG)	Hydro Quebec	Occidental Energy Ventures Corp.	Southern Company Services	SPP
CSU	Iberdrola Renewables	OGE	Southwest Generation	TRE
Dominion	IMPA	PacifiCorp	Southwest Power Pool	WECC

Table 3: Other Outreach	
NERC Standards and Compliance Workshop	ISO/RTO Council
NAGF	NERC News
NERC Standards Committee	EPRI

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

VAR Mapping Document

Transition of VAR-001-3 and VAR-002-2b (the *pro forma* standard)

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R1	Requirement R1	The *pro forma* creates adds additional sub-requirements that requires the policies and procedures to include criteria for system assessments. The assessments must now include steady-state limits, voltage stability limits and associated operating margins, and voltage schedules along with associated tolerance bands. The sub-requirements also now mandate that information is shared with neighboring TOPs and the applicable RC.
VAR-001-3 R2	Requirement R2	The new requirement has been updated to incorporate real-time and day-ahead scheduling of resources. It eliminates the need for the existing R7, R8, and R9.
VAR-001-3 R3	Requirement R3	The new requirement has been simplified by removing the need to maintain an exemption list. Instead, the standard focuses on whether the exemption criteria are known and whether a granted exemption was communicated to the applicable Generator.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R4	Requirement R4	The new requirements have been updated to allow the TOP to provide the voltage or Reactive Power schedule at either the high side or the low side of the GSU. Also as tolerance band is now required under the new requirement.
VAR-001-3 R5	Deleted	Pending a final rulemaking on P81, this requirement has been deleted.
VAR-001-3 R6	Requirement R5	The sub-requirement R6.1 was deleted because it is duplicative of VAR-002's requirement R1 and R2.
VAR-001-3 R7	Deleted	See comments for new R2.
VAR-001-3 R8	Deleted	See comments for new R2.
VAR-001-3 R9	Deleted	See comments for new R2.
VAR-001-3 R10	Deleted	This is duplicative of TOP-001-2 and the Tv definition.
VAR-001-3 R11	Requirement R6	The only change is the numbering due to other deletions.
VAR-001-3 R12	Deleted	This requirement was deleted because the EOP standards address taking any corrective action including load-shedding. Also the new TOP-002-3 R2 and TOP-001-2 R11 address the TOP taking corrective actions.

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b R1	Requirement R1	The requirement has not been modified.

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b R2	Requirement R2	The new *pro forma* requirement has been updated by including a new sub-requirement to allowing GOPs to only call in certain instances when deviating from voltage schedules .
VAR-002-2b R2	Requirement R3	The new *pro forma* requirement has been updated by including a new sub-requirement to allowing GOPs to investigate why the status has changed on AVR equipment before having to notify the TOP.
VAR-002-2b R2	Requirement R4	The requirement has not been modified.
VAR-002-2b R2	Requirement R5	The requirement has not been modified.

Compliance Operations

Draft Reliability Standard Compliance Guidance for VAR-001 and VAR-002

July 8, 2013

Introduction

The NERC Compliance department (Compliance) worked with the Informal VAR Group (IVG) in a review of pro forma VAR-001 and VAR-002 standards. The purpose of the review is to discuss the requirements of the pro forma standards to obtain an understanding of its intended purpose and necessary evidence to support compliance. The purpose of this document is to address specific questions posed by the IVG in order to aid in the wording of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance. In addition, a conclusion related to whether the pro forma standards provide reasonable guidance for compliance auditors is provided. However, this document makes no assessment as to the enforceability of the standard.

While all testing requires levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions will be used to aid in such auditor training.

IVG VAR-001 and VAR-002 Questions

Question 1

To show that VAR-001 policies or procedures are "implemented," would Compliance ask for a TOP to provide data around an "event?" Otherwise, would Compliance request TOPs to prove compliance over the entire audit period? What is the best way to provide sample data to support that VAR-001 requirements are being met?

Compliance Response to Question 1 (Compliance response in context of VAR-001 R1)

Part 1 – Compliance can use a range of approaches to understand and verify implementation. With regard to this standard, those approaches may include observing, interviewing, reviewing an entity's response to instances of voltage deviation that require operator intervention, as well as reviewing documentation for notifications of voltage deviations that may include exemption requests. Registered entities may also demonstrate the implementation of policies or procedures by providing documentation in connection with an event. Also, auditors may be independently aware of events occurring within the TOP's area, and the use of such events to determine the nature of an entity's response is evidence of implementation of policies and procedures. Alternatively, a lack of response to a known event could be evidence of noncompliance with implementation of policies and procedures.

Part 2 – Yes, the Rules of Procedure provide that a registered entity is required to be compliant with Reliability Standards during the audit period. A compliance audit should be appropriately scoped and testing designed to obtain a reasonable assurance of compliance. In this regard, though possible, it is unlikely an auditor would require levels of proof of compliance for an entire audit period and would use approaches such as those noted in Part 1 to gain reasonable assurance of compliance.

Part 3 – As noted in the answer to Part 1, there are a range of approaches to help an auditor determine compliance and those range of approaches should be used to help the registered entity demonstrate compliance. As noted above, those approaches may include observing, interviewing, providing documentation relative to an event, as well as documents generated during normal operations such as notifications of voltage deviations.

Question 2
For VAR-001 R2, would Compliance focus more on real-time directives? For the day-ahead time frame, is it enough to show studies that were used to schedule resources?

Compliance Response to Question 2
Part 1 – Compliance cannot commit to the level of testing that would or would not be performed on a requirement by requirement basis or favoring the testing of one sub-requirement over another. These determinations would be made in connection with the scoping of an audit for a specific registered entity.

Part 2 – No. The entity would be expected to provide the documentation for the day ahead scheduling in addition to documentation supporting that it was scheduled, as noted in the requirement.
The auditor would first gain an understanding of the entity's process for conducting the studies and the frequency the studies are performed. Based on the entities response, the auditor most likely would select a sample of studies to verify and ascertain whether the resulting actions, or non actions, were supported by such studies. Documented evidence existing at the time of the study selected by the auditor for verification would be considered stronger evidence than verbal explanations given by entities in response to inquiries during an audit.

Question 3
For VAR-001 R3, is the standard clear enough to allow for temporary exemptions?

Compliance Response to Question 3
Yes. The TOP would need to provide the criteria and evidence supporting the delivery of the exemption notification.

Question 4
With regard to VAR-002, will generators receive a violation for instances where a system event is affecting system voltage, but the generators made the appropriate conversions and set the AVRs to meet the original schedule provided by the TOP?

Compliance Response to Question 4 (Compliance response in context of VAR-002 R2)
No, the generator operators can only be responsible for maintaining the schedule provided by the TOP; if the TOP provides a new directive or schedule, the GOP is required to follow the new directive.

Question 5
Related to VAR-002, generators monitor voltage on both the low side and high side of the GSU and the "number" being monitored by the Generator will not always equate to the number provided by the TOP. Does this need to be spelled out in the requirement?

Compliance Response to Question 5 (Compliance response in context of VAR-002 R2)
The Generator should be able to provide documentation that identifies the "number" being monitored and the calculation demonstrating how the "number" equates to the schedule provided by the TOP.

Question 6
For VAR-002 R2, the Generator demonstrates compliance by executing the three sub-tasks. Is it clear that those are the only items that a Generator will need to do to maintain voltage? There are events when a unit will be dragged out of voltage schedule, and a unit is limited by its operating capacity to prevent such instances. Those instances should not be a violation under VAR-002 R2, if the GOP is doing everything possible to bring the unit back into a voltage schedule (i.e., the three sub-requirements).

Compliance Response to Question 6
The main requirement is clearly stated, that except for an exemption, each of the three sub-requirements must be performed. In this regard, the Generator must document their performance to provide evidence to the auditor of compliance. We have provided additional notes for R2.1-.3 below:

R2.1: Based on the language modification, the Generator may operate up to 30 minutes prior to notifying the TOP that the Generator cannot return to its schedule. The sub-requirement would not require the documentation for instances where a Generator returned to their schedule in 30 minutes or less. Instances greater than 30 minutes would require documentation supporting the Generator contacting the TOP, documentation showing when the Generator first began operating outside of the schedule and when the determination was made the GOP was no longer able to return to its schedule.

R2.2: Based on conversations with the IVG, the only alternative is to manually control the reactive output. In this regard, it is suggested that, unless another method exists, the language be changed to "shall use a manual method."

R2.3 The sub-requirement is self explanatory and would require the Generator to provide documentation supporting compliance or the written explanation.

Question 7
For VAR-002 requirement R3, the requirement allows for a 15 minute grace-period to reporting a status change, if the issue with reactive resource is corrected. Is that point clear? This requirement is concerned with allowing a Generator to resolve an issue with a resource without having to call or notify the TOP every time the status of the resources goes in and out of service. Also, the IVG would like for telemetered points to count as an automatic notification to the TOP. Is such notification acceptable to Compliance?

Compliance Response to Question 7
Part 1 – The Requirement is clear, notification is only required between minutes 16 and 30, regardless of restoration.
Part 2 – If telemetered points meet the requirement of a notification, the requirement will need to explain the supporting documentation that substantiates compliance (what evidence can be provided to an auditor.)

Conclusion

In general, Compliance finds the pro forma standards provide a reasonable level of guidance for Compliance Auditors to conduct audits in a consistent manner. The standard establishes timelines, data requirements, and ownership of specific actions. In general, the standard would provide reasonable guidance to develop training for Compliance Auditors to execute their reviews. Compliance does recommend the IVG address the issues noted in the previous section of this document related to the standards.

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.

Proposed Timeline for the VAR Standard Drafting Team (SDT)		
Anticipated Date	**Location**	**Event**
July 2013	-	SC Authorizes SAR and pro forma Standards for Posting
July 2013		Conduct Nominations for VAR Project
July 2013	-	Post SAR and pro forma Standards for 45-Day Initial Comment Period
August 2013	-	Conduct Ballot
September 2013	-	45-Day Comment Period and Ballot Closes
September 2013	TBD	VAR Standard Drafting Team Face to Face Meeting to Respond to Respond to Initial Comments and Revise as Necessary
September 2013	-	Conduct Final Ballot
November 7, 2013	-	NERC Board of Trustees Adoption
December 31, 2013	-	NERC Files Petition with the Applicable Governmental Authorities

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-001-4 & VAR-002-3

Ballot and Non-Binding Poll now open through September 3, 2013

Now Available

A ballot for **VAR-001-4 and VAR-002-3** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is open through **8 p.m. Eastern on Tuesday, September 3, 2013.**

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

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

As a reminder, this ballot is being conducted under the revised Standard Processes Manual, which requires all negative votes to have an associated comment submitted (or an indication of support of another entity's comments). Please see NERC's announcement regarding the balloting software updates and the guidance document, which explains how to cast your ballot and note if you've made a comment in the online comment form or support another entity's comment.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard(s). If the comments do not show the need for significant revisions, the standard(s) will proceed to a final ballot.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control VAR-001-4 & VAR-002-3

Comment Period: July 19, 2013 – September 3, 2013
Ballot Pools Forming Now: July 19, 2013 – August 19, 2013

Upcoming:
Ballot and Non-Binding Poll: August 23, 2013 – September 3, 2013

Now Available

A 45-day formal comment period for **VAR-001-4 and VAR-002-3** is open through **8 p.m. Eastern on Tuesday, September 3, 2013.** The standard authorization request (SAR) for this project is also posted for comment. Additional supporting documents are posted for information. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Monday, August 19, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

This project began with an informal development process to address outstanding FERC directives from Order 693 and compliance issues. The modifications to VAR-001 and VAR-002 were drafted in tandem, and several requirements in one standard reference the other standard. Accordingly, the standards are being balloted together. Further, in an effort to support Paragraph 81 and the results-based standard concepts, informal development is proposing six requirements for retirement. The goal is to present the standards to the NERC Board of Trustees in November 2013.

Background information, including other supporting documents for this project, can be found on the project page. Please contact either Soo Jin Kim, the standards developer or a participant on the informal development group if you would like additional information.

Instructions for Joining Ballot Pool(s)

Ballot pools are being formed for the standards mentioned and the associated non-binding polls in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submit an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pools

During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Ballot for VAR-001-4 & VAR-002-3: bp-2013-04_VAR_1_in@nerc.com
Non-Binding Poll for VAR-001-4 & VAR-002-3: bp-2013-04_VAR_NB_1_in@nerc.com

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Tuesday, September 3, 2013**. Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

A ballot for the standards and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Standard Drafting Team Nominations

Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1
Project 2010-04 Demand Data: MOD-031-1
Project 2013-04 Voltage and Reactive Control: VAR-001-3, VAR-002-4
Project 2010-01 Training: PER-005-2

Nomination Period Open: July 24, 2013 – August 2, 2013

Link to Official Nomination Form
Link to Word Version of Nomination Form

Background

These projects have recently transitioned from informal development to formal development. Ad hoc groups developed Standard Authorization Requests, pro-forma Reliability Standards, a technical white paper and supporting documents through the stakeholder consensus building informal development process which are currently posted for comment with upcoming ballots. The NERC Standards Committee is seeking industry experts to serve on standard drafting teams for formal development.

Each standard drafting team (SDT) is proposed to consist of a maximum of 10 members. SDT members are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings (projected to be 3 days a month) as well as participate in all the SDT meetings held via conference calls (projected to be 2 to 5 days a month) for the remainder of 2013. Nominees are asked to be mindful of the time commitment this project will require, and volunteer only if their schedule will allow them to actively participate.

Background information about each project including the projected schedule is available on the project pages. The stakeholders who comprised the ad hoc group participants can be found at the links below:

- Project 2010-03 Modeling Data
- Project 2010-04 Demand Data
- Project 2013-04 Voltage and Reactive Control
- Project 2010-01 Training

Notice to all ad hoc group participants: if you are interested in continuing on the SDT you must nominate yourself to be considered for possible inclusion on the team.

For all projects below, the following are beneficial, but not required: team members with experience in compliance, legal, regulatory, facilitation, technical writing, previous drafting team experience, or experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process. Any person interested in being chair of a SDT must be willing to undergo one half day of facilitation training prior to the first team meeting.

Further, nominees should have technical expertise in the subject matter of the standard drafting team on which they wish to serve, as identified below:

- Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1 – Nominees should have experience in one or more of the following areas: transmission planning, steady-state and dynamics modeling, and system model validation. The project is also seeking perspectives from each Interconnection and from various organizations whose functions are contemplated to be subject to the Reliability Standards.
- Project 2010-04 Demand Data: MOD-031-1 – Nominees should have experience in one or more of the following areas: transmission operations, transmission planning, operations planning, and resource planning.
- Project 2013-04 Voltage and Reactive Control: VAR-001-4, VAR-002-3 – Nominees should have experience in one or more of the following areas: transmission operations, transmission planning, reliability coordination, and generator operation.
- Project 2010-01 Training: PER-005-2 – Nominees should have experience in training or transmission and generation operations.

Instructions for Submitting a Nomination to Participate on a Standard Drafting Team

If you are interested in serving on a SDT, please complete this nomination form by **August 2, 2013**. One nomination form must be submitted for each SDT an individual wishes to volunteer for, describing the individual's experience or qualifications related to that project.

An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page.

Standards Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Nomination Form

Standard Drafting Team Members

Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1
Project 2010-04 Demand Data: MOD-031-1
Project 2013-04 Voltage and Reactive Control: VAR-001-3, VAR-002-4
Project 2010-01 Training: PER-005-2

If you are interested in serving on a standard drafting team for one of the projects above, please complete this nomination form by **August 2, 2013**. One nomination form should be submitted for each standard drafting team an individual wishes to volunteer for, describing the individual's experience or qualifications related to that project. If you have any questions, please contact Valerie Agnew at valerie.agnew@nerc.net.

By submitting the following information, you are indicating your willingness and agreement to actively participate in the Standard Drafting Team (SDT) meetings if appointed to the SDT by the Standards Committee. This means that if you are appointed to the SDT, you are expected to attend all (or at least the vast majority) of the face-to-face SDT meetings (projected to be 3 days a month) within the projected schedule as well as participate in all the SDT meetings held via conference calls (projected to be 3-5 days a month) for the durations of 2013. Nominees are asked to be mindful of the time commitment this project will require, and volunteer only if their schedule will allow them to actively participate. The projected schedules can be found on the project pages below.

- Project 2010-03 Modeling Data
- Project 2010-04 Demand Data
- Project 2013-04 Voltage and Reactive Control
- Project 2010-01 Training

Thank you for volunteering! All nominees will be contacted with the disposition of their nomination after the Standards Committee appoints a team for the project for which you have volunteered.

Name:	
Select the Project for which the nominee is volunteering:	☐ Project 2010-03 Modeling Data: MOD-032-1, MOD-033-1 ☐ Project 2010-04 Demand Data: MOD-031-1 ☐ Project 2013-04 Voltage and Reactive Control: VAR-001-3, VAR-002-4

	☐ Project 2010-01 Training: PER-005-2
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the selected Standard Drafting Team:
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR drafting team, standard drafting team, standard review team, or informal ad hoc group. ☐ Currently a member of the following SAR, standard drafting team(s), standard review team(s), or informal ad hoc group:
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team experience. ☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ ERCOT ☐ FRCC ☐ MRO	☐ NPCC ☐ RFC ☐ SERC	☐ SPP ☐ WECC ☐ NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority ☐ Compliance Enforcement Authority ☐ Distribution Provider ☐ Generator Operator ☐ Generator Owner ☐ Interchange Authority ☐ Load-serving Entity ☐ Market Operator ☐ Planning Coordinator	☐ Transmission Operator ☐ Transmission Owner ☐ Transmission Planner ☐ Transmission Service Provider ☐ Purchasing-selling Entity ☐ Reliability Coordinator ☐ Reliability Assurer ☐ Resource Planner

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name of your immediate supervisor if not provided above:			
Name:		Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control VAR-001-4 & VAR-002-3

Ballot and Non-Binding Poll Results

Now Available

A ballot for **VAR-001-4 and VAR-002-3** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, September 3, 2013.**

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 81.89%	Quorum: 79.95%
Approval: 43.79%	Supportive Opinions: 44.23%

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

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. The standard will then proceed to an additional comment period and ballot.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2013-04 Voltage and Reactive Control VAR-001-4 and VAR-002-3 ballot 1
Ballot Period:	8/23/2013 - 9/4/2013
Ballot Type:	Initial
Total # Votes:	330
Total Ballot Pool:	403
Quorum:	**81.89 % The Quorum has been reached**
Weighted Segment Vote:	43.79 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	107	1	35	0.449	43	0.551	0	10	19
2 - Segment 2	9	0.9	2	0.2	7	0.7	0	0	0
3 - Segment 3	90	1	33	0.493	34	0.507	0	6	17
4 - Segment 4	30	1	18	0.75	6	0.25	0	1	5
5 - Segment 5	99	1	27	0.38	44	0.62	0	5	23
6 - Segment 6	53	1	16	0.381	26	0.619	1	3	7
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	1	0.1	2	0.2	0	0	1
9 - Segment 9	3	0.3	1	0.1	2	0.2	0	0	0
10 - Segment 10	8	0.7	3	0.3	4	0.4	0	0	1
Totals	**403**	**7.2**	**136**	**3.153**	**168**	**4.047**	**1**	**25**	**73**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	COMMENT RECEIVED
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED

1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	COMMENT RECEIVED
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - (Group comments submitted by CAL ISO and Xcel Energy)
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Review Group)
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
				SUPPORTS

1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	THIRD PARTY COMMENTS (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Negative	COMMENT RECEIVED
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NERC Standards Review Forum)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid's supports comments provided by NPCC Reliability Standards Committee (RSC).)
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO-NSRF)
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan	Negative	COMMENT RECEIVED
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	COMMENT RECEIVED
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards

				Review Group)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council group comments)
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams	Negative	COMMENT RECEIVED
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	COMMENT RECEIVED
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Comments)
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	COMMENT RECEIVED
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
1	Texas Municipal Power Agency	Brent J Hebert	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED

1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC - NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	COMMENT RECEIVED
3	Ameren Services	Mark Peters	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
				SUPPORTS THIRD PARTY COMMENTS -

3	Colorado Springs Utilities	Charles Morgan	Negative	(Group comments by CAL ISO and Xcel Energy)
3	ComEd	John Bee	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (supporting NPCC group comments)
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Negative	COMMENT RECEIVED
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF & ACES)
3	Gulf Power Company	Paul C Caldwell	Negative	COMMENT RECEIVED
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Abstain	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments submitted by the MRO NERC Standards Review Forum (NSRF))
3	Mississippi Power	Jeff Franklin	Negative	COMMENT RECEIVED

3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RegStandards Committee)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NERC Standards Review Forum (NSRF))
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Comments)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	COMMENT RECEIVED
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
				SUPPORTS

3	Westar Energy	Bo Jones	Negative	THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy Comments)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	COMMENT RECEIVED
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	COMMENT RECEIVED
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Regional Standards Committee)
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren, SERC GS Committee)
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cooments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	

5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Negative	COMMENT RECEIVED
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	COMMENT RECEIVED
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Standards Working Group)
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC ISO Comments)
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC EC Generation Subcommittee)
5	Dynegy Inc.	Dan Roethemeyer	Negative	COMMENT RECEIVED
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs	Negative	SUPPORTS THIRD PARTY COMMENTS - SERC
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	Exelon Nuclear	Mark F Draper	Negative	COMMENT RECEIVED
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF & ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(FMPA)
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lafayette Utilities System	Jamie B Webb		
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Generator Forum Standards Review Team)
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	NextEra Energy	Allen D Schriver		
5	NiSource	Huston Ferguson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (We support comments previously submitted by SPP Standards Review Group.)
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	PacifiCorp	Bonnie Marino-Blair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kelly Cumiskey, PacifiCorp)
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF SRT)
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	

5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Chelan County	John Yale	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF SRT)
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Comments)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Negative	COMMENT RECEIVED
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Vandolah Power Company L.L.C.	Douglas A. Jensen		
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren, SERC GS Committee)
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	COMMENT RECEIVED
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (CAL ISO)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
6	Constellation Energy Commodities Group	David J Carlson	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF / ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO Comments)
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	NO COMMENT RECEIVED
6	Omaha Public Power District	Douglas Collins	Abstain	
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee comments.)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	COMMENT RECEIVED
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP's comments)
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	COMMENT RECEIVED
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	COMMENT RECEIVED
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from the SERC EC Generation Subcommittee submitted by Ben Deutsch on 9/3/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED

10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Non-binding Poll

Project 2013-04 VAR

Non-binding Poll Results	
Non-binding Poll Name:	Project 2013-04 VRC VAR-001-4, and VAR-002-3 NB Poll
Poll Period:	8/23/2013 - 9/4/2013
Total # Opinions:	295
Total Ballot Pool:	369
Summary Results:	79.95% of those who registerd to participate provided an opinion or an abstention; 44.23% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot		
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	COMMENT RECEIVED
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)

1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Review Group)
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD

				PARTY COMMENTS - (NERC Standards Review Forum)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports comments provided by NPCC Reliability Standards Committee (RSC).)
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan	Negative	COMMENT RECEIVED
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Abstain	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council group comments)
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of	Dale Dunckel	Affirmative	

	Okanogan County			
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Negative	COMMENT RECEIVED
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	COMMENT RECEIVED
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Comments)
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	COMMENT RECEIVED
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System	Gregory Campoli	Abstain	

	Operator			
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	COMMENT RECEIVED
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (supporting NPCC group comments)
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Negative	COMMENT RECEIVED
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF & ACES)
3	Gulf Power Company	Paul C Caldwell	Negative	COMMENT RECEIVED
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED

NERC

3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MEAG Power	Roger Brand	Abstain	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support comments submitted by the MRO NERC Standards Review Forum (NSRF))
3	Mississippi Power	Jeff Franklin	Negative	COMMENT RECEIVED
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Regional Standards Committee)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	

3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Comments)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	COMMENT RECEIVED
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	

4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Abstain	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	COMMENT RECEIVED
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Standards Working Group)
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC EC Generation Subcommittee)
5	Dynegy Inc.	Dan Roethemeyer	Negative	COMMENT RECEIVED
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs	Negative	SUPPORTS THIRD PARTY COMMENTS - SERC

5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF & ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Generator Forum Standards Review Team)
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Abstain	
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	NextEra Energy	Allen D Schriver		
5	NiSource	Huston Ferguson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (We support comments previously submitted by SPP Standards Review Group.)

5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF SRT)
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF SRT)
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee Comments)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	

6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	COMMENT RECEIVED
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Colorado Springs Utilities	Shannon Fair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cal ISO)
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF / ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Negative	COMMENT RECEIVED
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO Comments)
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	NO COMMENT RECEIVED
6	Omaha Public Power District	Douglas Collins	Abstain	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD

				PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC Generation Subcommittee comments.)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	COMMENT RECEIVED
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments from the SERC EC Generation Subcommittee submitted by Ben Deutsch on 9/3/13)
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (79 Responses)
Name (52 Responses)
Organization (52 Responses)
Group Name (27 Responses)
Lead Contact (27 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (8 Responses)
Comments (79 Responses)
Question 1 (65 Responses)
Question 1 Comments (71 Responses)
Question 2 (67 Responses)
Question 2 Comments (71 Responses)
Question 3 (59 Responses)
Question 3 Comments (71 Responses)
Question 4 (0 Responses)
Question 4 Comments (71 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
The SAR should not be posted with the Standard. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard's development or revision. Posting the Standard for comments and ballot means that the SAR is "water under the bridge", and that industry's input on the SAR doesn't mean anything.
Yes
VAR-002 uses footnote (3) on page 6 to clarify the phrase "voltage or Reactive Power schedule." VAR-001 does not use a footnote or otherwise define "voltage or Reactive Power schedule." Intead of using a footnote to clarify/define the phrase, add the phrase "voltage or Reactive Power schedule" to the Definitions of Terms Used in the Standard, making sure it is applicable to both VAR-001 and VAR-002. Suggest adding the following wording to both VAR-001 and VAR-002: Definitions of Terms Used in the Standard: Voltage or Reactive Power Schedule – A target value communicated by the Transmission Operator to the Generator Operator establishing a tolerance band within which the target value is to be maintained during a specified period. If this definition is added to VAR-001 and VAR-002, then VAR-002 footnote (3) should be deleted. For VAR-001-4: Recommend adding "upon request" to this sub-requirement to make it read: "Each Transmission Operator shall provide a copy of these documented policies or procedures to adjacent Transmission Operators, upon request." VAR-001 uses the term "real-time" (no capitalization) throughout, whereas VAR-002 uses the term "Real-time" (capitalized) in R1. The capitalized term is defined in the NERC Glossary of Terms Used. The Glossary definition is the meaning intended for both standards. Please use consistent terminology employing the capitalized Glossary term "Real-time" throughout both Standards. Regarding VAR-001, typically, the voltage and Reactive Power (VAR) output of a generator may be adjusted by one or more of three means: a no-load tap changer (NLTC), a load-tap changer (LTC), or an automatic voltage regulator (AVR). The requirements in the VAR-001 Standards should more fully and clearly address these Real-time and periodic NLTC, LTC and AVR changes or adjustments. The following wording changes are proposed for VAR-001 Requirements R1, R3, R4 and R6: The language of R1 includes key words such as "implemented" and "control voltage," representing Real-time actions taken by a TOP to keep voltages within limits that could be interpreted to include actions such as switching shunt capacitors/reactors, adjusting transformer taps, adjusting transfers, adjusting generation or other dynamic VAR sources (like SVC's). The intent of R1 may simply be to address the RC monitoring issue, as directed by FERC Order 742 (see Rationale for R1). However, the R1 language can also be interpreted to include the Real-time aspects of R4 creating a potential overlap. Depending on the interpretation and intent of the drafting team for R1, might R4 be a candidate for elimination? Regardless, clarity of wording and intent in R1 is needed. If the intent in R1 is to respond to FERC's

Order 742 directive to assure “monitoring,” then the Drafting Team should consider deleting the action verb “implemented.” The revised wording would read: R1. Each Transmission Operator shall have documented policies or procedures that are to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits … If “implemented” is not deleted, then it should be replaced by words conveying the intended meaning, e.g., “that are monitored and enforced.” However, there enforcement is inherent in all standards that all “documented policies or procedures” will be enforced. Application is verified by audit. Adding the phrase “that are implemented” is not needed, and can possibly lead to confusion. The TOP should only be required to develop exemption criteria in R3 if there is an established need for generator exemptions. Once the TOP has determined that there is a need for generator exemptions, only then should it be required to develop and implement exemption criteria. We recommend changing to word of R3 to not only conform to the appropriate Requirement format but include the preceding: R3. Each Transmission Operator shall determine the criteria that shall exempt generators from R4. Requirement R4 may already be covered by FAC-001 and Requirement R1 and may be deleted. But if not, it should be clarified recognizing the following: NLTCs are typically mechanically-fixed at time of generator interconnection and are only adjusted, if necessary, during a generator outage. The NLTCs may not be adjusted in Real-time. The TOP typically establishes initial voltage and Reactive Power requirements in the Interconnection Agreement under FAC-001-0, which states: R2. The Transmission Owner’s facility connection requirements shall address … R2.1.9. Voltage, Reactive Power, and power factor control. The interconnection provisions of R4 are covered in FAC standards. Non-Real-time Periodic timeframe changes in the NLTC settings may be addressed under Requirement R6. Requirement R6 does not appear to refer to Real-time operations and may be deleted from the Real-time standard. However, if it is not deleted, the wording should be revised to address NLTCs only. NLTCs are typically mechanically-fixed at time of generator interconnection and are only adjusted, if necessary, during a generator outage. The NLTCs may not be adjusted in Real-time. The initial NLTC settings are typically addressed during the generator interconnection process (see FAC-001). The need for a NLTC change is typically determined by the TOP through periodic (e.g., seasonal, 5-yr.) system studies. NLTCs adjustment are determined by and directed by the TOP. Alternatively, a load tap changer (LTC) may be adjusted by the GOP under load in Real-time. The setting of any LTC and the automatic voltage regulator (AVR) are typically under the control of the GOP. If this Requirement is referring to a LTC operation in Real-time, it is inappropriately assigned to the TOP. The GOP should have the flexibility to follow its voltage and Reactive Power schedule using the LTC and/or AVR. Alternatively, if the requirement is addressing changes applicable only to the NLTC, then it should be reworded accordingly. We assume the intent is to address NLTC tap changes only and recommend a wording/format change as follows: R6. Each Transmission Operator shall determine the need for generator step-up transformer no-load tap changes. 6.1 After consulting the Generator Operator regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Operator specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. R1 can be interpreted to require a TOP to have documented policies or procedures in place that can be implemented to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits as defined in Parts 1.1 to 1.3. However, Part 1.1 requires that the policy/procedure shall include criteria used in system assessments. What is “system assessments” intended to mean? What is “criteria for the assessments” intended to mean, especially in relation to “established steady-state limits, voltage stability limits, etc.? If the assessments were meant to yield the “limits”, then there it is confusing as to what limits are intended to be developed in relation to the “established” limits. In Order 693, P. 1868, FERC directs the ERO to modify VAR-001-1 to include more detailed and definitive requirements on “established limits”. Does it mean more detailed and definitive requirements on stipulating voltage and reactive requirements with respect to established limits (SOLs, IROLs, voltage level, etc.), or does it mean more details on limits (boundaries) of the interconnection voltages as implied by Requirement R8 of the existing VAR-001 Standard? Requirement R1 does not provide clarity since Part 1.1. refers to “established steady-state limits, voltage stability limits”, which is different from the “established limits” presented in the R8 of the existing VAR-001 standard. Requirement R1 as presented does not provide any clarity as to what practice a TOP is required to meet. Requirement R1 as presented is unclear on its objective and the exact actions required of the Responsible Entity as there are a number of “criteria” and “limits” in the main requirement and its part 1.1 that are confusing and subject to different interpretations. R1 as presented will leave a Responsible Entity not knowing what it needs to do to meet Requirement and its reliability objectives.

Suggest that R1 and its parts be revised to clarify its intent, especially on the who, the specific actions and expected outcome according to the results-based principle and guideline. With respect to part 1.1, Measure M1 asks for evidence that proves voltage is currently being monitored. "Such evidence may include, but is not limited to: 1) proof that points are telemetered, 2) alarms are functioning, and 3) during events of low or high voltage the policies and procedures are being followed to respond to control voltage levels." These examples of evidence do not reflect the scope and depth of R1 and Parts 1.1 (the criteria and assessment parts). R2 as presented appears to go beyond the FERC directive that RC be included to be assigned the "monitoring responsibility" as R2 now requires the RC to "….perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1." The inclusion of RC in this requirement is also inconsistent with the view presented in the Informal Consideration with respect to parity between TOPs and RCs. Parts 2.1 and 2.2 stipulate a number of tasks for the TOPs with respect to operating or directing the real-time operation of devices necessary to regulate transmission voltage and reactive flow, and to ensure that sufficient reactive resources have been scheduled to meet the acceptable day-ahead voltage limits identified in Requirement R1. These tasks do not involve the RC. It thus raises a question on the need for including RC in the main requirement when it is not required to take further actions to assure its assessment of "sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions" can be fulfilled in real-time operations. We believe the inclusion of RC in this requirement is inappropriate, or if there is a compelling reason to include the RC, then Parts 2.1 and 2.2 are insufficient to assure the RC's assessment can be supported in real-time operations. Requirement R2, Part 2.1 stipulates that the Transmission Operator has two things (operate or direct) that can be done to "…regulate transmission voltage and reactive flow necessary to regulate transmission voltage and reactive flow which may include…". Part 2.1 should only contain one thing. The order of Requirements R3 and R4 should be reversed since the exemption criteria (R3) should appear after the overarching requirements for GOs to maintain a voltage or Reactive Power schedule and tolerance band. Regarding Requirement R5, suggest replacing "know" with "monitor". This provides an active approach, which is appropriately reflected by the wording in Measure M5. In the Compliance Section, there is no requirement for the RC to retain evidence for Measure M2. Further, there is no requirement for the TOP to retain evidence for Measures M5 and M6. Regarding the VSL for R1, there is no explicit requirement in R1 for the TOP to provide a copy of the assessment criteria to its RC or neighbor TOPs since the assessment criteria are supposed to be included in the policy or procedure document. The Low VSL thus serves no purpose. Further, from the standpoint of meeting the intent of Requirement R1, there is little to no difference between having documented policies or procedures which do not include any of the elements stipulated in Parts 1.1 to 1.3, and having no documented policies or procedures at all. Suggest to remove the Low VSL and the High VSL, and keep the Moderate VSL and revise the Severe VSL to include the condition presented in the High VSL as an "OR" condition under the Severe VSL. Regarding the VSL for R2, throughout R2 there are no specific requirements for having policies and procedures implemented to have sufficient MVARs. R2 requires the TOP and RC to perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions. Part 2.2 stipulates the requirements for scheduling reactive resources to meet the reactive requirements resulting from day-ahead assessments. Part 2.1 stipulates the requirement to operate or direct the real-time operation of devices necessary to regulate transmission voltage and reactive flow. While the Moderate VSL, which addresses non-compliance with Part 2.2 and appears to be reasonable, the Severe VSL does not correspond to how Part 2.1 is presented. The condition that "A lack of real-time operations is also severe." seems irrelevant to Part 2.1 when it comes to operating or directing the real-time operation of devices necessary to regulate transmission voltage and reactive flow. There can be no lack of real-time operations, but a TOP may totally ignore the operations or directing the operations of devices necessary to regulate transmission voltage and reactive flow. There is no VSL for the RC failing to meet R2. Hence, the RC is assigned a responsibility but its compliance is not measured and there is no VSL to determine its non-compliance. Regarding the VSL for R5, the conditions in the Moderate and High VSLs are irrelevant to the requirement. R5 requires a TOP to know (monitor) the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in its system. The Moderate VSL makes reference to a "stable area", which is totally irrelevant and out of context of R5. In the High VSL, the TOP not knowing "the status of important equipment in weaker areas that were identified in assessments as part of R1." are also irrelevant and

out of context of R5. Finally, there is no Severe VSL. What constitutes a total failure to comply with Requirement R5? Regarding the VSL for R6, the Low VSL should have an “is”, not an “are”. There is no Severe VSL and hence there is no condition to constitute a total failure to comply with Requirement R6. VAR-002-3 Regarding Measure M2, M2 presents the scenarios where a Generator Operator may not be able to meet a voltage schedule or comply with the TOP’s directive, and how a GOP may manage the situations. The description part does not belong in a Measure, and should be moved to the Background Information Section that a Results-based standard template has made provision for. Regarding Measure M3, the latter part of M3 is not presented in a manner to require the evidence to demonstrate compliance. Suggest revising M3 to read: The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3, or evidence that the status had been restored within the first 15 minutes of such change. For all Measures, there are no examples of evidence provided. It would be appropriate if after each of the “evidence”, additional wording “such as log, recording, or other documents” so as to be consistent with the way Measures are presented in other standards. Regarding Evidence Retention, it would be appropriate to reference the Measure Number for the GO’s and the GOP’s data retention requirements.
No
NERC’s Reliability Issue Steering Committee (RISC) is charged to address emerging reliability issues and recommend preferred approaches to manage such issues. Whether or not the TOP/GOP voltage coordination issue should rise up to a risk level that warrants special attention by the industry, and whether the appropriate way to address this issue in a standard project will be best evaluated and determined by the RISC. We suggest that the Drafting Team nominate this issue for RISC consideration. The Requirements in both VAR-001-4 and VAR-002-3 should be reviewed to ensure they are in the correct NERC Standard Development format.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No
Yes
VAR-001-4: R1: In addition to controlling voltage, R1 also requires procedure for control of reactive flow. Reactive flows are hard to control and there is no reliability benefits for controlling the reactive flow. Reference to reactive flow should be deleted. R2: This requirement is a duplication of requirements in other standards such as in TPL standards. Reactive assessment should not be part of this standard. R5: This requirement is unnecessary. A GO is already obligated to provide the status of AVR and PSS information to TO (VAR-002-3). This requirement puts unnecessary burden on TO to monitor status of all AVR and PSS. Particularly, TO does not have any value in knowing the PSS status. He cannot do anything with that information. There is no reliability benefit of this requirement. If the drafting team thinks that knowing the status of PSS is necessary for TO, please provide the rational. VAR-002-3: R3: Notifying the status of PSS is unnecessary since TO will not use that information for operating system any differently or do anything with that information. If the drafting team thinks that this information is necessary, please provide the rational.
Yes
There is no need to restrict the time to 15 minutes. It should be at least 30 minutes. For any system changes typically 30 minutes are allowed to readjust the system. A TO not knowing the status of AVR for 60 minutes is not going to cause any reliability issue. GO should be given 30 minutes to fix the problem and then 30 minutes to notify the TO if the problem is not fixed.
Individual
Terry Volkmann
Volkmann Consulting

No
Yes
VAR-001-4 R3 establishes the ability for the TOP to exempt a GOP from maintaining a voltage schedule and directing the GOP to perform in automatic and exempts from the report requirements that would be established under R4. VAR-002-3 R1 establishes the GOP requirement to operate in the automatic mode. This requirement is not prefaced with "unless exempted by the TOP". It is unclear that if the TOP has exempted the GOP from maintaining a voltage schedule in automatic and reporting AVR status changes, the GOP still needs to keep the AVR in automatic. If a generator is equipped with an AVR, but exempted by the TOP, one can interpret that the GOP still must maintain a voltage schedule (not TOP established) in automatic. Recommend modifying R1 with the lead in "unless exempted by the TOP,". This would clarify the intended operation of the GOP.
No
Individual
Thomas Foltz
American Electric Power
No
Yes
R5: We recommend that Requirement 5 and the associated subrequirement be applicable only to the Generator Owner and not split between the Generator Owner and Generator Operator.
No
AEP believes that additional coordination regarding high-side voltage schedules compared to low-side measurement (which is typical at the power plants) would be beneficial.
Individual
Dan Roethemeyer
Dynegy
Yes
In VAR-001-4 Applicability section 4.3 says “Generator Operators within the Western Interconnection”. But nowhere in the Standard does it discuss what are the responsibilities of the GOPs in the Western Interconnection. It has to do with the WECC variance to VAR-001 issued by FERC on 6-20-13 but VAR-001-4 does not explain it.
No
Yes
VAR-002-2 R2 requires the GOP to notify its associated TO within 15 minutes if both: 1) the GOP operated outside the voltage schedule for 15 minutes and 2) the GOP is no longer able to return to its voltage schedule. Regarding item 2) above, how long does the GOP have to return to its voltage schedule? Most GOPs eventually return to the voltage schedule, e.g., either a sister unit at the plant site returns from a forced outage boosting voltage or the wider area voltage returns to normal due to circumstances beyond the GOP’s control. If the GOP returns to its voltage schedule 24 hrs later, does that require notification? Regarding item 1) above, setting the threshold for operating outside the voltage schedule at 15 minutes seems overly prescriptive. Suppose a generator operates outside the voltage schedule for 14 mintues and then operates inside the schedule for 5 minutes, and the process repeats itself. The hourly average voltage may be outside the schedule, but the 15 minute threshold is never reached, so no notification is required. A simpler alternative to the 15 minute threshold would be to use a one hour clock average before reporting is required and eliminate item 2).

Group
US Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation (Reclamation) suggests that VAR-001-4 and VAR-002-3 should be combined into one standard because of the reciprocal requirements in each standard (e.g., VAR-001-4 R6 would require the Transmission Operator (TOP) to consult with the Generator Owner (GO) regarding TAP setting changes, and VAR-002-3 R5 requires the GO to ensure that tap positions are changed when possible). If the drafting team prefers not to combine the two standards, Reclamation requests that the drafting team explain why two standards are more appropriate. The Bureau of Reclamation (Reclamation) notes that VAR-001-4 appears to apply to Generator Operators within the Western Interconnection, and the White Paper on the VAR Standards dated July 18, 2013 explains that this is because the WECC variance in VAR-001-3 is retained in VAR-001-4. If the variance is retained, Reclamation suggests that the entire text of the variance should be included in VAR-001-4 rather than incorporated by reference in order to prevent confusion among registered entities. Reclamation also requests that the drafting team explain why the WECC variance would not be beneficial for reliability continent-wide.
Yes
The Bureau of Reclamation (Reclamation) notes that VAR-001-4 appears to apply to Generator Operators within the Western Interconnection, and the White Paper on the VAR Standards dated July 18, 2013 explains that this is because the WECC variance in VAR-001-3 is retained in VAR-001-4. If the variance is retained, Reclamation suggests that the entire text of the variance should be included in VAR-001-4 rather than incorporated by reference in order to prevent confusion among registered entities. Reclamation also requests that the drafting team explain why the WECC variance would not be beneficial for reliability continent-wide.
No
Reclamation believes that the scope of the project is appropriate.
Individual
Dave Willis
Idaho Power Company
No
Yes
VAR-002-3 R2, I think that this requirement is going to be very hard to document compliance. Monitoring voltage at the POI, tracking the time the voltage exceeds the limits and notification to the TOP all will need to be captured.
Yes
I think that the 30 minute notification after a 15 minute violations is reasonable but it think this requirement will be very hard to prove or disprove compliance. Is the intent for the TOP to monitor the GOP or is the GOP responsible to show compliance when there is a deviation. A GOP may not be monitoring the voltage at the POI and unaware that they are outside the voltage limits. If the GOP is not able to bring the bus voltage to within limits and contacts the TOP is there a length of time that they can be outside the bounds.
Coordination is a problem for the requirements in many standards and I’m not sure of a good way to improve coordination. I do not believe that this Standards Project is the time or place to address the issue.
Individual
R. J. Mattey
Ohio Valley Electric Corporation

No
Yes
VAR-001-4, R1, includes details about assessments and critierial that are more related to MOD and TPL standards. VAR-002-3, R2, now has two 15 minute times to track for compliance related to not maintaining a voltage schedule.
Yes
Only that additional compliance time frames have been added. Will a shorter time frame reduce the reliability gap?
This issue should not be addressed in compliance standards. Voltage coordination should be a function of the ERO as part of its normal function, handled through the appropriate committees.
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
The technical discussion paper last paragraph has a topic on the minority issue of voltage control and states the drafting team will investigate. I believe this should be included in the SAR.
Yes.
Individual
Ronnie C. Hoeinghaus
City of Garland
No
Yes
On all the requirements in VAR-001-4, the Time Horizons are defined as “Operations”. The NERC Document defining Time Horizons lists Operations Planning, Same-day Operations, Real-time Operations, and Operations Assessment – which one do you mean for each requirement? This needs to be corrected for each requirement.
No
Individual
John Seelke
Public Service Enterprise Group
Agree
NAGF SRT (North American Generator Forum Standards Review Team)
Individual
Steve Hill
Northern California Power Agency
Yes
Directive from P1875 states, "... we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available and offline simulation tools where online tools are not available, to assist real time Operations." What online

models are being referred to? How do we know they are correct in their assessment? If the new TPL standard R5 is approved would this directive and R1 & R5 in the proposed VAR standard be redundant?
Yes
Same comment as in questions and comments as in Comment 1 in regards to R1 & R5. Controllable Load should be defined in R2.
Yes
There does not seem to be consensus on when a reliability gap would be created when expanding the time requirement, but is there consensus that there is no reliability gap with the 15 minute timeframe? There should be data to justify the timeframe to some confidence level.
I need to think about the first question more, but in regard to the second question I think the issue of improving votage coordination between TOP's and GOPs is vital to address in a Standards project since the Standard applies to GOPs
Group
MRO NERC Standards Review Forum
Russel Mountjoy
Yes
VAR-001-4: R4 of VAR-001-4 seems to have a potential inconsistency between the parenthetical statement and the balance of the requirement. It is suggested that R4 be rewritten and simplified as follows: "Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band for Generator Operators at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion".[Note the SDT may want to review the concept of "mutually agreed upon" instead of the TOP's discretion] Additionally, there needs to be a feedback loop from the GOP to the TOP regarding the voltage schedule. The following allows the GOP to provide feedback regarding the feasability of the schedule. A recommended R4.2 for VAR-001 : R4.2 The Generator Operator shall review the voltage or Reactive Power schedule and tolerance band provided by the Transmission Operator and inform the Transmission Operator of any conditions that would prevent the Generator Operator from complying with the schedule or tolerance band, along with the technical basis for that determination. The question that then comes up is, what does the TOP do if the GOP cannot comply with the schedule as presented? Recommended R4.3 to read: R4.3 If the Generator Operator is unable to comply with the voltage or Reactive Power schedule or tolerance band as provided by the Transmission Operator, the Transmission Operator shall (a) modify the voltage schedule within the parameters established in the documented policies and procedures established in R1, taking into account the Generator Operator's limitations, or (b) exempt the Generator Operator from following the voltage schedule or tolerance band using the criteria established in R3.To allow for coordination of operations between Transmission Operators and Generator Operators, it is suggest the the words "that is mutually agreed" after the words "timeframe for making the changes" be added in requirement R6 of VAR-001-4. A recommended change to R6 of VAR-001 is as follows: "After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes that is mutually agreed, and technical justification for these changes." That is, the change should normally wait until it can be rolled into a scheduled downtime event. VAR-002-3 The following change to the rationale for R2 of VAR-002-3 is suggested: Change "...or when the unit is too small to raise voltage" to, "...or when the unit is too small to control voltage within the tolerance band." The implications of footnote 4 to requirement R2 of VAR-002 is unclear in that it is not identified what stablility limit is being referred to: that of the voltage regulator or a transmission system stablility limit. If it is a transmission system stability limit it is unclear how a generator operator would be aware of it and how the generator operator should change the unit capability accordingly. R2 should read, "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each unit's capabilities4) as directed by the Transmission Operator." R2.1 should read, "If the voltage drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator when both of the following conditions are met: 1) the parameter being controlled has been outside the prescribed voltage or Reactive Power schedule tolerance band for 15 minutes; and 2) the GOP is

unable to return the parameter being controlled to within the voltage or Reactive Power schedule tolerance band." What's drifting is the grid, not the generators. R2.2 should read, "When a generator's automatic voltage regulator is out-of-service, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator, unless the TOP grants an exemption." The purpose of this change is to reference the process established in R3 of VAR-001.
No
The NSRF request that "within 30 calendar days of a request." (of R4) be modified to "within 30 calendar days or agreed upon schedule of a request." This will allow small GOPss to establish a working rapport with their TOPs, since many small GOPs may only have one subject matter expert that has this technical information. Please break the Standards apart into separate ballots. Since the applicable entities are different and the Standards cover different reliability related requirements. Please clarify within Measure 2, that not every day of "system studies" are required to be on-hand as evidence, if the study has not changed, as stated in the last sentence of measure 2.
Group
Tennessee Valley Authority
Brandy Spraker
No
Yes
TVA appreciates the effort that the ad-hoc group has put into this revision. For VAR-001-4, TVA supports the SERC OC Review Group comments. For VAR-002-3, TVA has the following two comments: In R1, please add language to ensure that the TOp has the authority to exempt a generator unit. M2 reads like another requirement or technical rationale. Timing requirements should be made clear in the requirement itself, and the measurement should only detail the evidence needed for the corresponding requirement.
Yes
For R2, TVA requests that notification be based on voltage readings taken no more often than 60 minutes and no less often than 30 minutes. The degree of signal conditioning allowed should be addressed, expressed as a maximum interval for averaging the variable on which the reading is based. The time that the Generator Operator has to notify the Transmission Operator of a voltage reading outside the published schedule would be no greater than 15 minutes. Paragraph 2.1 would then read: "Each Generator Operator shall take voltage readings no less often than every 60 minutes. Voltage readings shall be averaged over a time interval no greater than 30 minutes. The Generator Operator shall notify its associated Transmission Operator within 15 minutes or a length of time determined and communicated by the Transmission Operator when the following conditions are met: 1) the GOP is operating outside of the prescribed voltage or Reactive Power schedule tolerance band at the time of the latest reading; 2) the GOP is no longer able to return to its voltage or Reactive Power schedule; and 3) no previous notification has been made for the same continuous excursion out of schedule."
Individual
Christy Koncz
Public Service Enterprise Group
No
Yes
VAR-001-4 a. In R4, the standard provides the TOP discretion on whether the voltage schedule provided is on the high or low side of the GSU "at the interconnection point between the generator facilitry and the Transmission Owner's facilities to be maintained by each generator. As written, the

sentence makes no sense. The interconnection point MAY BE on the GSU high side, our it MAY BE at a point where the GO's interconnection facilities connect to the TO's facilities. In other words, the GSU low side, the GSU high side, and the interconnection point may be three different places for a particular generator. To avoid this confusion, we recommend that R4 should be rewritten as the first sentence in R4 in VAR-001-3, with the footnote omitted, as shown below: "R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator." This change maintains the framework which has existed through three versions of VAR-001. b. With regard to the WECC exception, page 11 under the "Regional Variance" section states: "Regional Variance for the Western Electricity Coordinating Council from VAR-001-3 is retained." We understand it is the intent for VAR-001-3 to be retired, so this reference presents a potential reference problem unless all parts of VAR-001-3 are retired EXCEPT Section E, which contains the WECC Variance. We recommend that Section E in VAR-001-3 in its entirety be brought into VAR-001-4 so that the new standard stands alone. VAR-002-3 With the suggested modifications in VAR-001-4 above, we suggest the following changes to VAR-002-3: c. In R2, subpart 2.1, the phrase "If a GOP drifts out of schedule" should be modified to "If a GOP's generator drifts out of schedule." d. In M2, we have both questions and suggested modifications. i. We do not understand why, in this sentence is in M2 what the phrase "based on existing equipment at its facility" refers to. Is the team referring to the equipment for monitoring the voltage? If not, what is intended? ii. Delete the following: "Therefore, GOPs have the option to operate on a voltage schedule on either the high-side or convert the high-side schedule to a low-side schedule at the GOP's discretion. For units that monitor on the low-side/terminal voltage, Generator Operators shall provide evidence of the method of conversion from the high-side schedule to low-side monitoring." This is not longer needed based upon the changes recommended in VAR-001-4 to NOT provide the TOP with discretion on the reference point for the voltage schedule. iii. For the sentence "Evidence may include, but is not limited to Generator Operator logs, SCADA data, phone logs, and any other alarming notifications that would alert the Transmission Operator that both conditions were met," we suggest that "and" be changed to "or."
No
In M3, the phrase "no call is necessary" should be changed to "no notification is necessary."
The single paragraph in the white paper was not specific enough to warrant a comment. Those that have concerns should express them through suggested modifications of the SAR, which defines the project's scope.
Individual
Jack Stamper
Clark Public Utilities
No
No
Yes
I do not see why there is a need for a fifteen minute cutuoff if the status has been restored. The requirement should allow 30 minutes to provide notification of a stauts change and if at any time during the 30 minutes the status is restored there should be no notification required. Under the current language, if the status is restored at 16 minutes, the GOP then needs to notify its TOP within the next 14 minutes that that generator status changed but returned to normal. How is that improving reliabiilty? It does not improve reliability. The purpose of the 30 minute delay is to allow a GOP to breifly investigate why the status or capabilty has changed and if the solution is at the plant, fix it quickly. I believe 30 minutes is a reasonable amount of time before the GOP needs to notify its TOP that a status or capability change has occured. The GOP will still attempt to fix it but has now notified the TOP. Whether the GOP fixed it in 2 minutes or 25 minutes it still does not need to notify the TOP until 30 minutes. If the problem is fixed before 30 minutes, the event is a non-event as far as the TOP is concerned (except that the TOP knows that it was briefly broken and is now fixed). The TOP is not going to change its operations or invoke some emergency plan for a generator that had a status or capabilty issue for 10 or 20 minutes but is now fine.

Individual
Michael Falvo
Independent Electricity System Operator
Yes
We question the need to ask this question when the consolidated standard is already posted for commenting and balloting. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard development/revision project. Posting the standard for balloting at the same time suggests that there is already a foregone conclusion on the need and the scope for this project , and that the industry's input on SAR would seem irrelevant. The IESO understands that posting a SAR and the draft standards for comment at the same time can improve standard development efficiency, and we support it to the extent that sufficient technical information has been obtained to facilitate the development of a draft standard at the informal outreach stage. However, we are very concerned about the fact that the industry was asked to ballot the draft standard when the need and scope of the draft standard have not been commented on and supported by the industry, and the standard itself has not been drafted by a formal standard drafting team. Such an approach appears to: a. Deviates from the normal standards development process as presented in the Standards Process Manual (SPM); b. Contradicts and perhaps violates the intent of the established standard development process and ANSI principles to have new and revised standard formally developed through an open and inclusive process before being presented to the RBB for balloting. The industry is being asked to ballot a set of standards that has not been formally developed. This concept appears to be fundamentally flawed. We propose that the SDT convey our concern to the NERC senior management and the Standards Committee. We further suggest that NERC and the SC evaluate alternative approaches or make revisions to the SPM to provide the needed flexibility that can further improve the efficiency in standard development if certain elements in the existing SPM are assessed to restrict such improvements.
Yes
VAR-001-4 a. It is unclear on the main objective and the target reliability outcome of Requirement R1, and the intent of the proposed changes in relation to the directive in P. 1868 in Order 693. We interpret R1 to require a TOP to have documented policies or procedures in place that can be implemented to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits as defined in Parts 1.1 to 1.3. However, Part 1.1 requires that the policy/procedure shall include criteria used in system assessments. It is unclear as to what "system assessments" means? Does it mean assessments of the TOP area's reliability performance with respect to the voltage levels and Mvar flows and any limits (SOLs, IROLs, reactive capability)? Or does it mean the system assessment that yields the "limits" (SOLs, IROLs, reactive requirements, etc.) which provide the target and guideline for the establishment, monitoring, and control of voltage levels and Mvar flows? It is also unclear as to what the "criteria of the assessments" means in the second sentence of Part 1.1, especially in relation to "established steady-state limits, voltage stability limits, etc. if the answer to the above question is that the assessments were meant to yield the "limits", then there is a confusion as to what limits are intended to be developed in relation to the "established" limits. In Order 693, P. 1868, FERC directs the ERO to modify VAR-001-1 to include more detailed and definitive requirements on "established limits". However, it is unclear what this directive really means. Does it mean more details and definitive requirement on stipulating voltage and reactive requirements with respect to established limits (SOLs, IROLs, voltage level, etc.) or does it mean more details on limits (boundaries) of the interconnection voltages as implied by Requirement R8 of the existing VAR-001 standard? Requirement R1 does not provide this clarity since Part 1.1. refers to "established steady-state limits, voltage stability limits", which is different than the "established limits" presented in the R8 of the existing VAR-001 standard. It is our understanding that as a general practice, a TOP will assess if there exists any reliability concerns that can be caused by voltage levels and instability to develop operating limits (SOLs or IROLs) to ensure reliable operations. The operating limits may be expressed in voltage level, pre and post-contingency power flow level, reactive support requirements or any combination of the above. The operating limits so established will provide a linkage between the SOL, voltage level and reactive power capability/reserve requirement either explicitly or implicitly. System Operators will monitor the key parameters including

voltage level, power flow level and reactive power flow/reserve/capability to meet the SOL boundary conditions. Requirement R1 as presented does not provide any clarity as to what is it that in the practice that a TOP is required to meet. Requirement R1 as presented is unclear on its objective and the exact actions required of the Responsible Entity as there are a number of “criteria” and “limits” in the main requirement and its Part 1.1 that are confusing and subject to different interpretation. R1 as presented will leave a Responsible Entity not knowing what it needs to do to meet Requirement and its reliability objectives. We suggest the SDT to revise R1 and its parts to clarify its intent, especially on the who, the specific actions and expected outcome according to the results-based principle and guideline. Note that with respect to Part 1.1, Measure M1 asks for evidence that proves voltage is currently being monitored. Such evidence may include, but is not limited to: 1) proof that points are telemetered, 2) alarms are functioning, and 3) during events of low or high voltage the policies and procedures are being followed to respond to control voltage levels. These examples of evidence do not reflect the scope and depth of R1 and Parts 1.1 (the criteria and the assessment parts). b. FERC directive 1855 directs NERC to include Reliability Coordinator as applicable entities and include a new requirement(s) that identifies the reliability coordinator’s monitoring responsibilities. In the Informal Consideration specific to this directive presented in the White Paper, it is indicated that: “Although some entities in Texas provided feedback that certain RCs perform functions equivalent to a TOP, the informal development group did not expand VAR-001 to give parity to TOPs and RCs.” R2 as presented appears to go beyond the FERC directive that RC be included to be assigned the “monitoring responsibility” as R2 now requires the RC to “….perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1”. The inclusion of RC in this requirement is also inconsistent with the view presented in the Informal Consideration with respect to parity between TOPs and RCs. Parts 2.1 and 2.2 stipulates a number of tasks for the TOPs with respect to operating or directing the real-time operation of devices necessary to regulate transmission voltage and reactive flow, and to ensure that sufficient reactive resources have been scheduled to meet acceptable day-ahead voltage limits identified in Requirement R1. These tasks do not involve the RC. It thus raises a question on the need for including RC in the main requirement when it is not required to take further actions to assure its assessment of “sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions” can be fulfilled in real-time operations. We believe the inclusion of RC in this requirement is inappropriate, or if there is a compelling reason to include the RC, then Parts 2.1 and 2.2 are insufficient to assure the RC’s assessment can be supported in real-time operations. c. Requirement R2, Part 2.1 stipulates that: “Each Transmission Operator shall operate or direct the real-time operation of devices necessary to regulate transmission voltage and reactive flow necessary to regulate transmission voltage and reactive flow which may include…” We do not understand this requirement as it contains two sets of “necessary to regulate transmission voltage and reactive flow”. If this is a typographical error, please correct it. d. We do not have any concerns or comments on R3 and R4 as presented, but suggest that their order be reversed since the exemption criteria (R3) should appear after the overarching requirements for GOs to maintain a voltage or Reactive Power schedule and tolerance band. e. R5: we suggest to change the word “know” to “monitor”. This provides an active approach, which is appropriately reflected by the wording in Measure M4. f. In the Compliance Section, there is no requirement for the RC to retain evidence for Measure M2. Further, there is no requirement for the TOP to retain evidence for Measures M5 and M6. g. VSL for R1: There is no explicit requirement in R1 for the TOP to provide a copy of the assessment criteria to its RC or neighbor TOPs since the assessment criteria are supposed to be included in the policy or procedure document. The Low VSL thus serves no purpose whatsoever. Further, from the standpoint of meeting the intent of Requirement R1, there is little to no difference between having documented policies or procedures which do not include any of the elements stipulated in Parts 1.1 to 1.3, and having no documented policies or procedures at all. In the former case, the documented policies or procedures provide absolutely no value, and hence is it a total violation of the intent of R1. We suggest to remove the Low VSL and the High VSL, and keep the Moderate VSL and revise the Severe VSL to include the condition presented in the High VSL as an “OR” condition under the Severe VSL. h. VSL for R2: Throughout R2, there are not specific requirements for having policies and procedures implemented to have sufficient Mvars. R2 requires the TOP and RC to perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions. Part 2.2 stipulates the requirements for scheduling reactive resources to meet

the reactive requirements resulting from day-ahead assessments. Part 2.1 stipulates the requirement to operate or direct the real-time operation of devices necessary to regulate transmission voltage and reactive flow. While the Moderate VSL which address non-compliance with Part 2.2 and appears to be reasonable, the Severe VSL does not correspond to how Part 2.1 is presented. Further, the condition that "A lack of real-time operations is also severe." seems irrelevant to Part 2.1 when it comes to operating or directing the real-time operation of devices necessary to regulate transmission voltage and reactive flow. There can be no lack of real-time operations, but a TOP may totally ignore the operations or directing the operations of devices necessary to regulate transmission voltage and reactive flow. Finally, there is no VSL for the RC failing to meet R2. Hence, RC is assigned a responsibility but its compliance is not measured and there is no VSL to determine its non-compliance. i. VSL for R5: The conditions in the Moderate and High VSLs are irrelevant to the requirement. R5 requires a TOP to know (monitor) the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. The Moderate VSL makes reference to a "stable area", which is totally irrelevant and out of context of R5. In the High VSL, the TOP not knowing "the status of important equipment in weaker areas that were identified in assessments as part of R1." are also irrelevant and out of context of R5. Finally, there is no Severe VSL. It begs the question on: what constitutes a total failure to comply with Requirement R5? j. VSL for R6: The Low VSL should have an "is", not an "are". Also, there is no Severe VSL and hence there is no condition to constitute a total failure to comply with Requirement R6. VAR-002-3 k. Measure M2: A good part of M2 presents the scenarios where a Generator Operator may not be able to meet voltage schedule or comply with the TOP's directive, and how a GOP may mange the situations. The description part does not belong to a Measure, and should be moved to the Background Information Section that a Results-based standard template has made provision for. l. Measure M3: the latter part of M3 is not presented in a manner to require the evidence to demonstrate compliance. We suggest M3 be revised to: The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3, or evidence that the status had been restored within the first 15 minutes of such change. m. For all Measures, there are no examples of evidence provided. It will be appropriate if after each of the "evidence", additional wording "such as log, recording, or other documents" so as to be consistent with the way measures are presented in other standards. n. Evidence Retention: It will be appropriate to reference the Measure Number for the GO's and the GOP's data retention requirements.
No
NERC's Reliability Issue Steering Committee (RISC) is charged to address emerging reliability issues and recommend preferred approaches to manage such issues. Whether or not the TOP/GOP voltage coordination issue should rise up to a risk level that warrants special attention by the industry, and whether the appropriate way to address this issue in a standard project will be best evaluated and determined by the RISC. We suggest that the SDT nominate this issue to the RISC for its deliberation.
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
Yes
The SDT should revisit VAR-002-3 Requirement R2 (including sub-requirements) and Measure M2. Generators should be required to operate in automatic voltage control mode and implement a setpoint consistent with the voltage target (schedule, etc.). The current requirement combined with the measure presents a framework that opens new reliability gaps. For example, in the new framework, if the voltage in a localized area goes low, the generators that notice the drop first are encouraged to deviate from actions that are predictable and take independent action to alter their control systems to provide the system more VARs. This presents three problems: 1) The ideal situation would be for the Transmission Operator to allow sufficient time for all of the generators under its control to automatically respond and then issue specific dispatch instructions to those units that are optimally able to resolve the issue; 2) When numerous generators take independent action, it's questionable as

to whether the Transmission Operator’s real-time evaluations of system contingencies are accurate b/c the assumptions related to how a generator will respond are no longer accurate and are unpredicatable due to the independent actions taken by GOPs; and 3) The generators that are slower to notice the voltage dip will likely not alter their control system parameters; allow for the automatic voltage regulator to respond (at which point adequate voltage will likely be restored); and, potentially, these units will have an economic advantage over similarly sized units because they are supplying less VARs than the units that took independent action (If you generate more VARS you can generate less Watts at maximum MVA on the generator capability curve). Additionally, Measure M2’s statement “For units that monitor on the low-side/terminal voltage, Generator Operators shall provide evidence of the method of conversion from the high-side schedule to low-side monitoring” creates a hidden defacto requirement for those units that control their units based on the low-side of the GSUT. It’s unclear how possession of a conversion method without any clear criteria for what should be included in the conversion method could 1) improve system reliability and 2) be evaluated by an auditor during a compliance audit. The majority of generators on the grid are controlled on the low-side of the GSUT. Under normal conditions, since generator’s operation is validated when the unit is brought on-line and voltage schedules should consider N-1 and credible N-2 contingencies, the voltage drop across and losses through the GSUT should have minimal impact (on an individual generator basis) on the voltage quality of the grid. If the technical concern is based on the aggregated impact of GSUTs’ voltage regulation varing with loading, then criteria for a methodology should be developed for those units that do not have the capability to monitor the high side voltage in real-time. However, industry input feedback indicates that only a minority of generation units that control on the low-side of the GSUT do not have high-side monitoring. The majority of units that control their AVR based on the low-side of the GSUT do see the high-side voltage and would notify the Transmission Operator of a deviation from the voltage schedule lasting longer than 15 minutes (VAR-002 R2), which would allow the Transmission Operator to direct the Generator Operators under their control to correct the deviation in a predictable and economic fashion AND would allow the Transmission Operator to calibrate any assumptions / variables necessary in their real-time models so that the real-time evaluations reflect accurate input data. Additionally, we would suggest that the models used by Transmission Operator to satisfy requirements R1 and R2 of the draft VAR-001 standard should account for the GSUT’s voltage regulation characteristics under normal system operation in order to accurately reflect that Generators are controlling the low-side bus.
If the Transmission Operator has not reached a pre-defined system operating alarm / limit and the Generator Operator is already operating with its automatic voltage regulatory in voltage control mode, what reliability concern is alleviated by the Generator Operator notifying the Transmission Operator that the voltage on the Generator Operator is monitoring has drifted off of schedule? The majority of units on the grid are unable to move the grid voltage by themselves, which is why VAR-002 requires that the aggregate operate in voltage control mode, and the likely cause of the event is a system contingency that the Transmission Operator has: A) planned for in their development of operating limits and is still within their pre-defined operating limits; B) has not planned for and is still within their pre-defined operating limits; or C) has not planned for and is outside of their pre-defined operating limits AND should be the only one taking independent action so that the system’s response to the Transmission Operator’s actions is predictable.
Individual
David Jendras
Ameren
No
Yes
For the most part we agree with the GS Subcommittee comments but we also have included are our specific comments below.
Yes
(1) R2 – We request the SDT to clarify this requirement. As it is written we believe operators may be confused of knowing when the new "15 minute" time period will start. Since it seems (under the draft) to be OK, that we can drift in and out of the Voltage Schedule for several hours if the operator

thinks the machine can get back on the VS later. How will our operators know when the 15 minute report trigger has occurred? (2) R2 – We believe the 15 minute time period is too short for mandatory reporting to the TOS. We ask the SDT to consider that currently there is no specific time period, and therefore we will need to modify our procedures accordingly. (3) Whether in VAR-001 or VAR-002 temporary exemptions are not appropriate. There may be circumstances that a generator should be declared exempt consistent with VAR-001 Requirement 3. These type of exemptions should be declared and documented outside of any particular period of inability to maintain the voltage schedule. Rather than have temporary exemptions if a generator were unable to operate in AVR or if operating in AVR the generator could not operate in the band of the voltage schedule, language should reflect that the notification of the inability is made to the TOP and the TOP will provide further instruction for operation, i.e. a set VAR output, a specific power factor, to the unit D-curve, etc. This would ensure that even if a generator could not meet the voltage schedule they should be as near the voltage schedule as is possible. Being exempted might give the generator the notion, "Since I am unable to get to my voltage schedule and I am therefore exempt, it does not matter how I operate." That should never be the case. (4) Whether in VAR-001 or VAR-002 temporary exemptions are not appropriate. There may be circumstances that a generator should be declared exempt consistent with VAR-001 Requirement 3. These type of exemptions should be declared and documented outside of any particular period of inability to maintain the voltage schedule. Rather than have temporary exemptions if a generator were unable to operate in AVR or if operating in AVR the generator could not operate in the band of the voltage schedule, language should reflect that the notification of the inability is made to the TOP and the TOP will provide further instruction for operation, i.e. a set VAR output, a specific power factor, to the unit D-curve, etc. This would ensure that even if a generator could not meet the voltage schedule they should be as near the voltage schedule as is possible. Being exempted might give the generator the notion, "Since I am unable to get to my voltage schedule and I am therefore exempt, it does not matter how I operate." That should never be the case. (5) M2 – A "30 minute" time period is allowed in M2 that appears to not be included, explained or mentioned in R2, please clarify. (6) We believe the TOP should set the reporting time period and it should not be set in the Standard. Our TOP has told us is the 15 minuet reporting is excessive and not necessary for reliable operation of the transmission system. (7) M2 – The first sentence of M2 requires the GOP to "make all attempts to operate within the tolerance bands provided by the TOP". We ask the SDT to explain from a generator perspective and provide an example for how this can be proven to an auditor?
Individual
Chris de Graffenried
Consolidate Edison Co. of NY, Inc.
Agree
Northeast Power Coordinating Council (NPCC) - All comments.
Individual
David Burke
Orange and Rockland Utilities, Inc
Agree
Northeast Power Coordinating Council (NPCC) - all comments.
Group
FirstEnergy
Larry Raczkowski
No
No
Yes
FE believes that #2 of Part 2.1 of Requirement 2 needs clarity. Since both conditions of Part 2.1 must be met, there should be a time parameter associated with #2. Otherwise, unless something

catastrophic happens, #2 will always be true, ie, we expect to be back on schedule at some time. We propose the folloing for #2 of Part 2.1 of Requirement 2 2) the GOP is unable to return to its voltage or Reactive Power schedule within 30 minutes of operating outside the prescribed schedule.
Individual
Michelle R D'Antuono
Ingelside Cogeneration LP (Occidental Chemical Corporation)
Yes
Ingleside Cogeneration LP supports the changes that have been made to both VAR standards. First, we agree that the removal of FERC's two LSE-related directives can be justified using the Paragraph 81 criteria. Directive 1858, which calls for LSEs to take on Reactive Power responsibilities consistent with PSEs, can be retired (as can VAR-001-2 R5) since those actions are already governed by the OATT. Similarly, the directive that LSEs maintain power factors within a given range is a normal part of interconnection agreements. Since both the OATT and pro-forma interconnection agreements are under regulatory control, reliability requirements are an unnecessary redundancy. Secondly, we agree with the need to include precise language in the measures to assure that Compliance Enforcement Authorities are looking for situations that present true risk to the BES. For example, the measure for VAR-002-3 R2 clearly accounts for those configurations where the GOP monitors voltage and reactive power flows at the generator output instead of the interconnection. In these cases, the CEA needs to understand that a conversion mechanism is sufficient – and not insist that high-side voltage and reative power monitoring is specifically required.
Yes
In particular, Ingleside Cogeneration would like to see the changes made to VAR-002-3 R3 take effect. We agree that there needs to be a level of tolerance around the communication of an AVR outages – those that are restored within 15 minutes pose no viable threat to the BES and only serve to distract the Transmission Operator from more pressing tasks. Although it does not change our vote to approve both of the VAR standards, we would like to suggest that a referece could be added under R1 to capture the same 15 minute criteria. Otherwise it seems possible that any uncommunicated AVR outage will violate R1, even if compliant with R3.
No
Ingleside Cogeneration would hesitate to call for more standards development activity related to TOP/GOP voltage and reactive communication. In our view, the issue does not appear during normal and semi-normal operations (i.e.; the generator is able to maintain voltage and reactive power within tolerance without exceeding its Facility Ratings). It may be a different story during an event where transients driven by the external network exceed a generation facility's capabilities. Since the proper action to take relies on the character of the transient – whether it is of long-duration/short-duration – and the topology of the local system, and the availability of other nearby reactive resources, the GOP can only take best-effort steps to maintain output to the TOP's schedule. We rely on guidance from the TOP if there are actions that must be taken beyond that point. For example, if a GOP were to make a change to a voltage setpoint outside of the threshold range without the TOP's guidance, the impact to the local system may actually worsen. Ingleside understands that during an emergency, the TOP may be otherwise engaged with many other operating entities – and may need the GOP to take helpful actions to stabilize the situation without direct supervision. However, there needs to be some pre-developed universal criteria in place before we would be comfortable proceding in this direction. In our view, this is an issue best taken up in a NERC sub-committee or task force – not a SDT.
Individual
David Austin / Ed Mackowicz
NIPSCO
Yes
We would like to see this project divided into two separate projects/ ballots. We are fine with the proposed VAR-002-3, but have some concerns with VAR-001-4. Ultimately, this means we must vote

negative for both standards instead of just one.
Yes
1. VAR-001 causes concern for the uncertainty of how to come up with a basis of how we plan operations. Is our performance over the last "x" years enough to justify no change, or do we need to study for voltage and VARs for the day(s) ahead and in real time (two extremes)? 2. There are discrepancies or vagueness between interpretations in new VAR standards and other standards like TOP. Which one trumps the other? 3. In general, the individual standards can be made to work. However, the interdependencies and the ability to go off on a tangential path between VAR, TOP and other related standards is troublesome. While each standard may be good as a solo act, they do not make a symphony together. RECOMMENDATIONS: A. All of the standards should be placed on a matrix so that interdependencies are identified and coordinated in application and measurement. B. The standards need to be stable over time as opposed to new ones being voted on before the previous one is implemented. C. A multi-year process where interdependent standards are adjusted and implemented in unison will yield a productive effort by the industry towards being more reliable rather than concentrating on avoidance of violations.
No
Individual
Brett Holland
Kansas City Power & Light
No
Yes
In VAR-001-4, depending on what periodicity and type of studies required in R2, this could overly burdensome to the registered entities to show evidence of compliance.
No
We would add that any proposed improvement to the voltage coordination between the TOPs and GOPs is a suggested guidance or level of expectation.
Group
Salt River Project
Bob Steiger
No
No
No
No comments from SRP
Individual
Lynda Kupfer
Puget Sound Energy
No
Yes
VAR-001-4 Comments Requirement R2 appears to be a mix of planning and operational processes. Since the main section of the requirement only addresses the planning process, part 2.1, which

addresses operational issues, seems out of place. In addition, since part 2.2 goes back to addressing planning processes, part 2.1 also seems out of sequence. This could be addressed by revising the main section of requirement R2 to address how the planning and operational aspects interrelate and then reordering parts 2.1 and 2.2. Alternatively and preferably, part 2.1 could be a stand-alone requirement, since it also addresses complying with the limits under the processes required by requirement R1. The drafting team should consider deleting the language "and direct the Generator Operator to comply with the schedule in automatic voltage control (the AVR is in service and controlling voltage)" from part 4.1 of requirement R4. Since VAR-002 requires the GOPs to operate in AVR mode and to follow the voltage schedule, the quoted language is both redundant and administrative in nature. Minor conforming changes would be necessary in VAR-002 (replacing the phase "as directed" with "provided" where that standard references the schedule should be sufficient to address this change). The last sentence of measure M5 should be deleted since it is redundant with EOP-008-1, which requires TOPs to have backup control center functionality available to address the loss of primary control center functionality. Losing the ability to monitor voltage would be a loss of primary control center functionality that is addressed by EOP-008-1.
Yes
VAR-002-3 Comment R2.1 condition 2 is vague and unclear how this should be interpreted "…no longer able to return…" What if you knew you were going to be able to return to schedule tomorrow? Would you need to report?
Individual
Herb Schrayshuen
Self
No
Yes
VAR-002 footnote (3) on page 6 offers a definition of the phrase "voltage or Reactive Power schedule." VAR-001 does not define "voltage or Reactive Power schedule." The term "voltage or Reactive Power schedule" should be defined for both standards. The voltage and Reactive Power (VAR) output of a generator is adjusted by several methods. The requirements in the VAR-001 Standard should state in terms of an action oriented result, what is expected. In VAR-002 M2 provides situations where a Generator Operator may not be able to meet a voltage schedule or comply with the TOP's directive. The description does not belong in a Measure, and should be moved to the Background Information Section of the Results-based standard. The proposed requirements in both VAR-001 and VAR-002 should be carefully reviewed to ensure they meet the expectations of a results based standard.
No
Group
Tacoma Public Utilities
Michael Hill
Yes
Concerned about the significant overlap in these standards vs: their long term accuracy.
Yes

VAR-001: -R3, Concern over the TO setting the criteria for when an AVR may be out of service. Could look to the current exceptions table for guidence. -R4 is poorly written and needs editing. Are we to specify the schedule a the point of interconnection, GSU hi side, GSU lo side, or a combination? Also, R3 allows the TO to exempt when the AVR must be in service, but R4.1 doesn't reference this exemption. VAR-002: -R1 confilcts directly with VAR-001 R4.1. Again, I read VAR-001 R4.1 to state the TO is giving the GO a directive to always be in AVR mode. No room is given for exceptions, (could easily correct this).
No
Individual
Kayleigh Wilkerson
Lincoln Electric System
MRO NSRF
No
Yes
Although supportive of the drafting team's efforts, LES is concerned with the removal of the FERC-approved interpretation previously appended to VAR-002-2b. Per the Interpretation, the Transmission Operator is permitted the option of directing the Generator Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode. In consideration that Requirements R1 and R2 of VAR-002 have not changed significantly, it is difficult to discern whether or not the Interpretation still applies. To ensure clarity going forward, LES recommends the interpretation either be appended to VAR-002-3 as well or else the drafting team further modify the requirements and/or measures to allow the TOP to direct the GO to run in a mode other than constant voltage.
Group
SERC OC Review Group
Catherine Wesley
Yes
There is a general concern with this proposed standard that it will create further administrative burden for the TOP/RC as well as the back office staff. Additionally, the opportunity exists that the number of calls between the GOP and TOP will increase without materially enhancing BES reliability. Further, how would these standards be used to evaluate the compliance of a unit which has their AVR taken off auto for testing?
Yes
VAR-001-4 Comments: R1.1.2. Each Transmission Operator shall Delete: "provide a copy of these documented policies or procedures to adjacent Transmission Operators" make plans available with a written request so entities requiring documents have access. R1.1.3. Each Transmission Operator shall Delete:"provide a copy of these documented policies or procedures to its Reliability Coordinator." make plans available with a written request so entities requiring documents have access. R2. Each Transmission Operator and Reliability Coordinator shall perform assessments on their respective areas in order to ensure sufficient reactive resources are available Delete: "for scheduling" to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1. R2.2.2. As a result of the assessments, each Transmission Operator shall ensure that sufficient reactive resources Delete: " have been scheduled" Add: "are available" to meet acceptable day-ahead voltage limits identified in Requirement R1. Sufficient reactive resources may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; and controllable load. M2 (excerpt): During a "real-time event" where voltage must be adjusted, a Transmission Operator shall show evidence to show directions were given to adjust the operation of capacitive and inductive resources. It is requested that the SDT provide additional

clarification what is meant by “real-time event” and whether it refers to normal operations or disturbances. SDT Question: How does the SDT anticipate this measure be used to evaluate the compliance of a unit which has their AVR taken off auto for testing? M3 (excerpt): For temporary exemptions, evidence showing the exemptions were granted must be provided. If the exemptions were given verbally from the Transmission Operator, the phone recordings or emails commemorating the phone call must be provided. For temporary exemptions, the evidence of communication must also include the timeframe for how long the exemption will last. We believe that this measure will increase the administrative burden placed on the TOP/GOP in real-time. R4.4.1. The Transmission Operator shall provide the voltage or Reactive Power schedule and tolerance band to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode. Delete:”(the AVR is in service and controlling voltage).“ R5. The Transmission Operator shall know the status of Delete:”all transmission” Add: “ BES” Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. Request that the SDT review R5 to ensure that it is not a duplicative of a TOP standard. M5. The Transmission Operator shall have evidence to show Reactive Power resources are being monitored. Evidence may include, but is not limited to screen shots of EMS/SCADA data, alarms, and phone logs. In the event the monitoring system does not work, each Transmission Operator should have a protocol in place to show these resources are being monitored. Request the SDT to add further clarification for AVR and PSS. VAR-002-3 Comments: 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) unless Delete:”the Generator Operator has notified the Transmission Operator of one of the following: “a generator has been has been exempted from operating in the AVR voltage control mode by the Transmission Operator or the Generator Operator has notified the Transmission Operator of one of the following: M1. Add: "Unless exempted" the Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1. 2.1. If a GOP drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator within 15 minutes when both of the following conditions are met: 1) the GOP is operating outside of the prescribed voltage or Reactive Power schedule tolerance band for Change from 15 to 30: 30 minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule. M2 excerpt: 1) Communications with the TOP when the Generator Operator was operating outside of the prescribed voltage or Reactive Power schedule tolerance band for 30 minutes Delete: “or less the 30 minutes allow for 15 minutes to call and 15 minutes to be outside of the tolerance band)” AND Generator Operator is no longer able to return to its voltage or Reactive Power schedule; 2) R3. Request a threshold be defined for the term “capability change” M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3. If the status has been restored within the first 15 minutes, no call is necessary Delete: "therefore, if a status on Reactive Power resource has changed, and that change lasts greater than 15 minutes, the GOP must notify its associated TOP within 30 minutes of when the change first occurred.”
Yes
We are unclear on how the draft time period was arrived at. Without that information it is difficult to compare time periods. The concern is the potential administrative burden placed on the TOP.
Strong communications between TOPs and GOPs is essential for reliability of the system. The concern that we have centers on the potential administrative burden that is placed on the TOPs and GOPs. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
Dominion NERC Compliance Policy
Randi Heise
No
Yes
VAR-001-4 • R1.1.2 amd R1.1.3 – Dominion suggests addition of the words ‘if requested”. This will

lessen administrative burden. • R2.1; “necessary to regulate transmission voltage and reactive flow” seems to be listed twice in this requirement, please clarify. • R3.1; Dominion suggests replacing “it” with “the Transmission Operator” • M3; Dominion suggests replacing “its” with “the Transmission Operators” • R6 - To allow for coordination of operations between Transmission Operators and Generator Operators, it is suggest the the words “that is mutually agreed” after the words “timeframe for making the changes” be added in requirement. VAR-002-3 • R1 – Dominion suggests requirement be revised to read “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) unless the Generator Operator has been exempted from operating in the AVR voltage control mode by the Transmission Operator or has notified the Transmission Operator of one of the following: • M1- Dominion suggests measure be revised to read “Unless exempted the Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1” • R2 - We suggest inclusion of a footnote to indicate that GOP is expected to be able to maintain voltage schedule as long as doing so would not violate its reactive capability curve or power factor requirement (as prescribed in other reliability standards such as FAC-001-0,. MOD-025-2 and MOD-026-1 or agreements such as an interconnection agreement). • R2.1 – Dominion suggests deletion of the words “If a GOP drifts out of schedule” because inclusion of these words could give the impression that an intentional deviation nullifies this sub-requirement. We do not believe this is the intent and therefore suggest that the sub-requirement read “Each Generator Operator shall notify its associated Transmission Operator within 30 minutes when both of the following conditions are met: 1) the GOP is operating outside of the prescribed voltage or Reactive Power schedule tolerance band for 30 minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule. • M2- Dominion does not agree with proposed language . GOP should be required to monitor and maintain voltage (high or low side of GSU) as specified by TOP in VAR-001-4@R4. • R3 & M3 - Dominion does not see value in the changes but do not oppose the revisions. In both VAR-001-4 and VAR-002-3 standards; GOP and TOP acrnomyns are used, Dominion suggests these acronyms be either spelled out or be updated to use GOP and TOP throughout the documents.
Yes
Dominion does not believe the additional granularity (15 minutes to determine and 15 to notify) is necessary or improves reliability. We believe the previous requirement (to inform within 30 minutes) is superior to the prosoed revision.
Dominion appreciates the IVG’s concentrated efforts to meet FERC Directives outlined in FERC Order No. 693 in suport of generator timeframes that ensure appropriate generation operation to maintain network voltage schedules. Dominion believes that the language and timeframe in VAR-002 provides for the generator to have adequate time to correct voltage drift and in the occasion where the cause of the voltage status change needs to be determined and then resolved, the timeframe of 30 minutes provides adequate time for the generator to notify the Transmission Operator.
Individual
John Canavan
NorthWestern Energy
Yes
It appears VAR-001-4, R5 is negated by VAR-002-3, R2 and R3. These standards should be coordinated with each other before they are submitted for a vote. Also we believe VAR-001-4, R2, requires additional clarification. Also, there are some overlaps within these new standards when compared to current NERC standards in place. For example FAC-014 and TOP-002. An overlap exists in establishing limits in accordance with the RC SOL methodology and the new RC SOL Methodology includes establishing limits for voltage stability and steady state voltage limits. TOP-002 states that the Transmission Operator shall perform seasonal, next day, and current day BES studies. Because of the overlaps we fear that entities could be subject to Double Jeopardy.

Individual
Scott Berry
Indiana Municipal Power Agency
Yes
Indiana Municipal Power Agency (IMPA) believes that there is some overlapping of requirements when comparing VAR-001-4 R1 to TOP-004-2 R6. IMPA recommends removing the common requirements (such as, monitorind and controlling voltage levels and real and reactive power flows-including additional requirements) from R1 of VAR-001-4. IMPA also believes that VAR-001-4 R5 can be deleted because TOP-006-2 R1 and R2 perform the same function. In addition
Group
Oklahoma Gas and Electric Co
Terri Pyle
Agree
Southwest Power Pool Standards Review Group.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Comments: VAR-001: 1. The rationale statement for R1 of VAR-001 says that it, “will allow each Transmission Operator (TOP) to establish its own policies and procedures,” regarding voltage schedules and tolerance bands. This wording does nothing to prevent specifying an unreasonably-tight bandwidth (e.g. +/- 0.5%), as some parties are now doing. The PPL NERC-Registered Affiliates suggest that R1.1 end as follows, “…voltage schedules along with associated tolerance bands of not less than 1.5% of the schedule voltage unless technically justified.” There may be some resistance to making the standard prescriptive, but it’s not a burdensome requirement, and it would be unfortunate to update the standard without addressing known abuses of the present version. 2. The statement, “Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band (at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion) at the interconnection point between the generator facility and the Transmission Owner's facilities,” in R4 of VAR-001 has a semantics glitch in that there is just one interconnect point. That is, mandating control at the interconnection eliminates any discretion in making the high vs. low-side selection. PPL suggests saying instead, “Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band, at the agreed upon metering point to which the GOP has access.” This will typically be either the transmission bus or the generator terminals. If the TOP specifies this as the TO’s “transmission bus”, the TO should be required to make the same voltage point used by the TOP available to the GOP to ensure both are seeing the exact same voltage. Additionally, there needs to be a feedback loop from the GOP to the TOP regarding the voltage schedule. This does not mean we want to spark a debate every time a schedule is provided, but simply add a step that allows a GOP to provide feedback regarding the feasibility of the schedule. A recommended R4.2: R4.2 The Generator Operator shall review the voltage or Reactive Power schedule and tolerance band provided by the Transmission Operator and inform the Transmission Operator of any conditions that would prevent the Generator Operator from complying with the

schedule or tolerance band, along with the technical basis for that determination. The question that then comes up is what does the TOP do if the GOP cannot comply with the schedule as presented? Recommended R4.3: R4.3 If the Generator Operator is unable to comply with the voltage or Reactive Power schedule or tolerance band as provided by the Transmission Operator, the Transmission Operator shall (a) modify the voltage schedule within the parameters established in the documented policies and procedures established in R1, taking into account the Generator Operator's limitations, or (b) exempt the Generator Operator from following the voltage schedule or tolerance band using the criteria established in R3. 3. PPL would like to see R6 of VAR-001 changed to, "After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes that is mutually agreed, and technical justification for these changes." That is, the change should normally wait until it can be rolled into a scheduled downtime event. VAR-002: 1. PPL suggests changing, "The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1," in M1 of VAR-002 to a more semantically neutral, "The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it did not operate a generator in the automatic voltage control mode." 2. PPL recommends the following changes to R2, for clarity; R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule3 (within each unit's ratings or capabilities4) as directed by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 3. PPL suggests corresponding changes to R2.1. Note that the time frames are left blank in our recommendation, as there is still much discussion within the industry as to what an appropriate timeframe would be; If the system bus voltage drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator within __ minutes when both of the following conditions are met: 1) the GOP has been operating outside of the prescribed voltage or Reactive Power schedule tolerance band5 for __ minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule. Notification to the TOP is not required if the GOP can return to schedule. 4. In line with the recommended changes above, PPL suggests changing M2 to; Generator Operators shall operate the generators to help minimize excursions outside the established tolerance bands for the agreed-upon metering point. It is recognized that excursions may occur outside of the tolerance bands during unit start-up and shut-down, during MW and MVAR loading at a transmission bus where multiple units are connected, during time of relatively sudden transmission system loading changes, during system events and when grid conditions are beyond the capability of a generator to correct. Therefore, when the system bus voltage is out of the tolerance band, the Generator Operator will not be held in non-compliance with this requirement if the sub-requirements 2.1, 2.2, and 2.3 are met. In order to identify when a unit is deviating from its schedule, GOPs will monitor voltage at the agreed upon metering point to which the GOP has access. Therefore, GOPs have the option to operate on a voltage schedule on either the high-side or convert the high-side schedule to a low-side schedule at the GOP's discretion. For units that monitor on the low-side/terminal voltage, Generator Operators shall provide evidence of the method of conversion from the high-side schedule to low-side monitoring. GOP shall have evidence to show compliance with requirement R2 by providing 1) Communications with the TOP when the Generator Operator was operating outside of the prescribed voltage or Reactive Power schedule tolerance band for __ minutes AND Generator Operator was unable to return the generator to operation within its voltage or Reactive Power schedule tolerance bands; 2) Generator Operator implemented an alternative method to control reactive output when the AVR was out-of-service or unavailable; 3) compliance with directive to modify voltage or a notification that the directive could not be met. Evidence may include, but is not limited to Generator Operator logs, SCADA data, phone logs, and any other alarming notifications that would alert the Transmission Operator that both conditions were met. Timing for Requirement R2.1 can be crucial during system events, and Generator Operators are expected to begin timing when notified of an event by the TOP as soon as the unit is operating outside of the tolerance band. Further, voltage documentation during a system event may be requested by an auditor to show measures were taken to bring the unit back into schedule. 5. To harmonize Footnote 4 with our recommended language for R2, PPL suggests Footnote 4 be revised to state; For the operations horizon, the GOP may choose a test-based or real-time method of establishing a unit's reactive power capability. The test-based capability is that determined for compliance with MOD-025. Parameters typically monitored for determining real-time capability may include 1) generator loading (MW, MVAR, amps), temperatures, and terminal voltage; 2) GSU

loading and temperatures; 3) auxiliary bus voltages; 4) plant auxiliary equipment loadings, temperatures, and voltages; 5) Generator and GSU Volts/Hz limits; 6) excitation system and/or AVR limits. 6. If R2.1 sticks, PPL would like to see M2 clearly state that "if the GOP can return to schedule, it does not have to notify the TOP." 7. For the new footnote 6 referenced above; The TOP is to establish an official-for-compliance bus and phase voltage point for monitoring compliance of generators controlling to the high-side voltage. An excursion begins for compliance purposes when the measured voltage exceeds the bandwidth boundary by a recognizable amount (0.5%). Multiple notifications to the TOP need not be made when the system voltage wanders back and forth across the bandwidth boundary. The system voltage must be back within the boundary for one hour before the next excursion counts as a separate event. 8. VAR-002, R2.2 should read, "When a generator's automatic voltage regulator is out-of-service, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator, unless the TOP grants an exemption." The purpose of this change is to reference the process established in R3 of VAR-001. 9. VAR-002, R4.1 should be revised to state; "For generator step-up and auxiliary transformers with nominal primary voltages equal to the generator terminal voltage:" This is to clarify that R4 is N/A to startup transformers and other station auxiliary transformers connected to a HV bus at a plant. 10. VAR-002, R5 should read, "after consultation with the Transmission Operator and agreement on a schedule regarding necessary step-up transformer tap changes…'" for the reason stated under comment 3 above. Regarding the Technical Whitepaper; 1. The statement on p.7 that, "the more VARs produced at a generating facility, the fewer MWs produced," would be true only if operating to the generator OEM D-curve limit, and many generation units are instead typically limited by generator voltage limits due to variations in aux bus voltages. Under the latter situation raising and lower reactive power export or import does not affect the MW capability. 2. The statement on p.7 that "the informal development group did not want to place numerical requirements on what the proper operational limits should be for the continent," fails to consider that there are present-day abuses of the system that should be addressed in the VAR-001 update. Self-policing isn't working, hence our comment #1 above. 3. Ref. "unit drifts out of schedule," on p.9 it is the system that is drifting, not generation units. 4. The statement on p.10, "This industry divide is not addressed in the pro forma standard presented today," appears to account for some of the ambiguity discussed in the North American Generator Forum's comments. PPL believes that requirements need to be unambiguous, however, and there must also exist explicit and achievable means of achieving compliance. 5. While there is a sentence in the measure that states it is clearly the generator's discretion as to whether they monitor (presumably control) low side or high side to demonstrate compliance, we believe that there is still a substantial amount of language in the Standard and the Whitepaper that would tend to cloud that by implying that a generator should monitor high side for compliance if you have high side equipment installed; in other words, the monitoring/control point is based on current installed equipment. 6. Additionally, the Whitepaper does nothing to shed light on whether generators should make manual moves to reactive output (by changing the AVR low side set-point) without explicit direction form the TOP which leaves the compliance application open for interpretation.
Yes
1. In order 693 Page 488 the FERC "directive" for VAR-002 stated, "Dynegy has suggested an improvement to Reliability Standard VAR-002-1, and NERC should consider this in its Reliability Standards development process." Dynegy's concern stated, "VAR-002-1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an 'incident' of noncompliance." Dynegy offered two alternatives to address their concern: "…[1] either more detail should be added to the Reliability Standard to cure this omission, Or [2] the Reliability Standard should require the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator." Their reasoning: "… this approach will eliminate the potential for undue discrimination and the imposition of overly conservative or excessively wide time frame requirements, both of which could be detrimental to grid reliability." Note that voltage tolerance band is not mentioned. 2. Going from NERC "should consider" Dynegy's suggested improvements to a very prescriptive time requirement (embedded in a VSL) in the current version of VAR-002 was a big step from the generation perspective. Also, it appears that Dynegy's second alternative was ignored during this step. 3. In the 2013 FERC Order approving VAR-002-2b (current version which became effective on July 1, 2013): PPL presented valid arguments against the "zero tolerance" time frame deviation introduced in the VSLs from the generator operator perspective (see Paragraphs 15 and 16). Both NERC and FERC rejected PPL's arguments. Paragraph

17 states, “NERC argues that the proposed modification would allow for a deviation in system voltage for up to 30 minutes to allow for time to correct an excursion and that such deviations from a voltage and reactive schedule is inappropriate because a deviation even up to a few minutes can negatively impact reliability.” Paragraph 18 goes on to say, “NERC maintains that significant voltage deviations for extended periods of time may lead to voltage collapse and can increase the potential for a wide-area impact to the reliability of the Bulk-Power System, and as such PPL Companies’ proposed modification to the VSL language should be rejected.” The context of the NERC and FERC discussions and agreement on the rigid time requirement apparently assumes all TOP’s voltage schedule tolerance bands are reasonable and “reliability based”. Also, there seems to be an absence of discussion on Dynegy’s 2nd alternative for the “the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator.” However, the Pro Forma VAR R1 will require each TOP to have documented policies or procedures used to “establish, monitor, and controls voltage levels and Reactive Power flows within limits as defined below: R1.1 These documented policies or procedures shall include criteria used in system assessments. The criteria for the assessments shall include established steady-state limits, voltage stability limits and associated operating margins, and voltage schedules along with associated tolerance bands.” Thus, a fair question on the Pro Forma standards follows: If VAR-001 R1.1 is met; can GOPs conclude that each TOP’s tolerance bands have a documented technical basis? If not, what mechanism will allow GOPs to question extremely narrow voltage or reactive power schedule tolerance bands that make compliance with VAR-002 R2.1 difficult or impossible? Note the Background discussions in the White Paper (see Pages 7 – 10). The discussion for VAR-001 R4 states, “The informal development group is cognizant of the fact that the nature of reactive power on the network varies depending on local conditions. Thus, the group focused on the process that the requirements would detail, not the proper numbers a TOP should enforce in the standard. For VAR-001, the group would not put operational limits on how a TOP should manage voltage stability for its regions; more specifically, the informal development group did not want to place numerical requirements on what the proper operational limits should be for the continent. Operating margins vary due to specific system characteristics as well as the operating conditions.” This begs the question: Why was this same rationale not applied in addressing the time frame? 4. The published reasons for the changes to VAR-002 include 1) eliminating nuisance calls and mitigating compliance issues for generators (i.e. non-reliability gap reducing violations), and 2) addressing the FERC directive to NERC to "consider a timeframe" for allowing a generator to be out of schedule before having to make a notification to its TOP. It could be argued that imposition of a very prescriptive time frame alone does not fully address the FERC “directive” language and the first Pro Forma objective of reducing nuisance calls (GOP to TOP), especially if the voltage tolerance bands are extremely tight or do not have a technical basis.
See responses to question 2 above.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
ReliabilityFirst has a fundamental overarching concern with the two proposed standards and believe the two standards in their draft state have major flaws. The two drafts are completely dependent on each other and when implemented individually do not make sense and actually conflict with each other. This interdependency on each other may cause serious issues and potential issues within compliance space and overall reliability. For example, Requirement R5 in VAR-001-4 requires the Transmission Operator to know the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. If the Generator never supplies the status, there is a potential for a potential violation on the Transmission Operator. Another example includes Requirement R3 in VAR-001-4. If the Transmission Operator fails notify the Generator Operator that they are exempted, there is a potential for non-compliance for the Generator Operator not complying with R2 in VAR-002-3. ReliabilityFirst believes the linkage between the two standards is crucial and recommends combining the two standards to address the contradictory aspects of the two standards.
Yes

ReliabilityFirst provides the following comments related to the requirements and VSLs for the draft VAR-001-4 standard: 1. Requirement R1, Part 1.1 - ReliabilityFirst seeks further clarity on what is meant by the term “system assessments” in Requirement R1, Part 1.1. Are these “system assessments” meant to be performed in the near-term or long-term time period and what do encompass? 2. Requirement R1, Part 1.2 and Part 1.2 - There is no periodicity for when the documented policies need to be provided to the relevant entities. There is also no stipulation on whether changes to these polices need to be provided as well. ReliabilityFirst offers the following for consideration for Part 1.2: “Each Transmission Operator shall provide a copy of these documented policies or procedures to adjacent Transmission Operators [within 30 calendar days of request and within 30 calendar days of any changes]”. 3. Requirement R2 - ReliabilityFirst seeks further clarity on what is meant by the term “assessments” in Requirement R2. Are these “assessments” meant to be performed in the near-term or long-term time period and what do encompass? 4. Requirement R2, Part 2.1 and Part 2.2 - The Reliability Coordinator is an applicable entity for the parent Requirement R2 but is not listed within Part 2.1 or Part 2.2. ReliabilityFirst believes the Reliability Coordinator is relevant to both of the sub-parts and should be referenced in both sub-parts. For Part 2.1, the Reliability Coordinator can “…direct the real-time operation of devices…” and for Part 2.2, the Reliability Coordinator can help in ensuring “…that sufficient reactive resources have been scheduled…” ReliabilityFirst recommends referencing the Reliability Coordinator within Part 2.1 and Part 2.2. 5. Time Horizons Q2 - The Time Horizons within a number of the requirements (e.g., “Operations”) do not align with the five NERC defined Time Horizons (i.e., Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations and Operations Assessment). ReliabilityFirst suggests the SDT review the NERC defined Time Horizons and modify the Time Horizons for all the requirements accordingly. The NERC defined Time Horizons are located at: http://www.nerc.com/pa/Stand/Resources/Documents/TimeHorizons.pdf. 6. VSL Requirement R1 - The High VSL should reference “sub-parts” rather than “sub-requirements.” NERC standards no longer include sub-requirements. 7. VSL Requirement R2 - The VSL is inconsistent with the language for Requirement R2. Based on the FERC VSL Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” The VSLs are missing reference to the Reliability Coordinator which is an applicable entity for Requirement R2. ReliabilityFirst recommends adding the Reliability Coordinator to the VSLs associated with Requirement R2. 8. VSL Requirement R3 - ReliabilityFirst believes there should be an associated VSL referencing sub-part 3.1. ReliabilityFirst recommends the following for consideration: "High VSL – “The TOP failed to notify the associated Generator Operator, In the event a Transmission Operator approves a generator as satisfying the exemption criteria.” 9. VSL Requirement R4 - ReliabilityFirst believes the word “some” in the high VSL is ambiguous and troublesome and ambiguous. ReliabilityFirst recommends the following for consideration: i. High VSL – The Transmission Operator specified a voltage or Reactive Power schedule and tolerance band but failed to provide the voltage or Reactive Power schedule and tolerance band to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode.” ii. Severe VSL – “The Transmission Operator failed to specify a voltage or Reactive Power schedule and tolerance band.” 10. VSL Requirement R5 - All Requirements are required to have a Severe VSL designation. Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. In cases where an entity completely failed to meet the intent of the requirement, it falls within the Severe category regardless of the risk to reliability (risk is dealt within the Violation Risk Factors). ReliabilityFirst recommends the following for consideration: i. Severe VSL – “The Transmission Operator failed to know the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. 11. VSL Requirement R6 - All Requirements are required to have Severe VSL designation. Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. In cases where an entity completely failed to meet the intent of the requirement, it falls within the Severe category regardless of the risk to reliability (risk is dealt within the Violation Risk Factors). ReliabilityFirst recommends the following for consideration: i. High VSL – “The Transmission Operator failed to provide documentation to the Generator Owner specifying either the required tap changes, a timeframe for making the changes, or technical justification for these changes.” ii. Severe VSL – “The Transmission Operator failed to provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.” ReliabilityFirst provides the following comments related to the requirements and VSLs for the draft VAR-002-3 standard: 1. Requirement R2, Part 2.2 - For consistency, spell out Generator Operator rather than listing the acronym “GOP.” 2. Requirement R5 -

The parent Requirement R5 is applicable to the Generator Owner while the sub-part 5.1 specifies the Generator Owner. The same applicable entity listed in the “parent” requirement should be the same as any associated sub-parts. This inconsistency needs to be remedied. 3. VSL Requirement R2 - The VSL is inconsistent with the language for Requirement R2. Based on the FERC VSL Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” ReliabilityFirst recommends the following for consideration: i. Severe VSL – “The Responsible entity failed to maintain the generator voltage or Reactive Power schedule as directed by the Transmission Operator in accordance with Requirement R2, parts 2.1, 2.2 and 2.3 “ 4. VSL Requirement R3 - The VSL is inconsistent with the language for Requirement R3. Based on the FERC VSL Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement.” ReliabilityFirst recommends the following for consideration: i. Severe VSL – “The Responsible entity failed to notify its associated Transmission Operator of a status or capability change on any generator Reactive Power resource within 30 minutes of the change.” 5. VSL Requirement R4 - The VSLs for Requirement R4 are completely inconsistent with the associated Requirement R4. Requirement R4 speaks to the Generator Owner providing data to the Transmission Operator while the VSL speaks to the failure of maintaining the generator voltage or reactive power schedule. ReliabilityFirst recommends reviewing Requirement R4 and developing VSLs consistent with the requirement. 6. VSL Requirement R5 - Requirement R5 is applicable to the Generator Owner while the associated VSL refers to the Generator Operator. This inconsistency needs to be remedied.
Individual
Scott Helyer
Tenaska, Inc.
No
Yes
We appreciate the language giving GOPs the option to monitor voltage on the low-side of the step-up transformers. This is a positive step, but work is still needed on the proposed standards. One concern is that VAR-001-4 allows the TOP to set voltage/reactive power schedules with tolerance bands. However, setting a tolerance band that is too narrow will require GOPs to frequently call TOPs as required in VAR-002-3 anytime the system causes the generator to move outside the tolerance band. The drafting team should consider whether a minimum tolerance band should be included in the standard that is enough to maintain a reliability voltage, but is large enough to minimize the potential for constant communications between GOPs and TOPs. Another concern is that VAR-002-3 R2 should specifically state that a GOP shall be allowed to convert a high-side schedule and control voltage on the low-side of the step-up transformer. Otherwise, R2 and M2 do not match as M2 is the only place where this language is provided. Further, VAR-002-3 requires the GOP to inform the TOP if the voltage drifts outside the tolerance bands set by the TOP. The problem is that GOPs may frequently find themselves outside the tolerance bands as the system voltage drifts if the TOP does not set appropriate tolerance bands.
No
Group
SERC EC Generation Subcommittee
David Thompson
Yes
There is a general concern with this proposed standard that it will create further administrative burden for the GOP, TOP, and RC, as well as the back office staff. Additionally, the high probability exists that the number of calls between the GOP and TOP will increase without materially enhancing BES reliability.

Yes
VAR-002-3 Comments: 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) unless Delete: "the Generator Operator has notified the Transmission Operator of one of the following:" a generator has been has been exempted from operating in the AVR voltage control mode by the Transmission Operator or the Generator Operator has notified the Transmission Operator of one of the following: M1. Add words “Unless exempted” the Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it Add words: “did not” operate a generator in the automatic voltage control mode. R2. Add "Unless exempted" by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within Replace: “applicable Facility Ratings” with Add words: “each unit’s ratings or capabilities4”) (NOTE: Footnote 4 should be associated with R2.2, not R2.1.) as directed by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 2.1. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met. [Delete Pro Forma 2.1 and replace it with Pro Forma 2.3. See our comments below and in our response to Question 3.] 2.2. When a generator’s automatic voltage regulator is out-of-service, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator Add words: “unless the TOP grants an exemption.” Comments: We feel that approach and language in VAR-002-2.b R2.2 should be retained. This approach reflects closer alignment with VAR-001-4 and current language in the Functional Model for Generator Operator expectations and current plant design features. The GS recommends NERC vet the White Paper for this standard through formal industry review, get stakeholder input and consensus as required per the Standards Process Manual, section 11. It appears that this standard has been written with the assumption that generators can monitor and directly control transmission bus voltage (only some monitor it and almost none directly control it). With the elimination of (the 18 Jul 2013 proposed) R2.1 this measure (M2) should be rewritten. The revised M2 should not include additional requirements. Comments: The M2 information should be considered during the revision of the White Paper. R3. Each Generator Operator shall notify its associated Transmission Operator of a status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability within 30 minutes of the change. If the status has been restored within the first 15 minutes of such change, then there is no need to call the TOP. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] Comments: The GS suggests clarifying the term “capability change” in the White Paper revision. There is considerable confusion about the time requirement and it is not clear that these are applicable to the AVR status question or the capability change question. It may make sense to separate these two requirements to allow better clarification. M3. The Generator Operator shall have evidence it notified its associated Transmission Operator Replace: “within 30 minutes of any of the changes identified” with Add words: “as required” in Requirement 3. If the status has been restored within the first 15 minutes, no call is necessary. R4. 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] 4.1. For generator step-up transformers and auxiliary transformers with Add words: “nominal” primary voltages equal to (Delete words “or greater than” the generator terminal voltage: Comments: (This is to clarify that R4 is N/A to startup transformers and other station auxiliary transformers connected to a HV bus at a plant.) R5. After consultation with the Transmission Operator Add words: “and agreement on schedule” 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]. Regarding the Technical Whitepaper; 1. The statement on p.7 that, “the more VARs produced at a generating facility, the fewer MWs produced,” would be true only if operating to the generator OEM D-curve limit, and many generation units are instead typically limited by generator voltage limits due to variations in aux bus voltages. Under the latter situation raising and lower reactive power export or import does not affect the MW capability. The NATF Model Practices Group has recognized that improvements in the way units are modeled for reactive power capability that respects other plant operating limitations, such as aux system voltage limits need to be investigated and have a project to review this issue. 2. The

statement on p.7 that "the informal development group did not want to place numerical requirements on what the proper operational limits should be for the continent," fails to consider that there are present-day abuses of the system that should be addressed in the VAR-001 update. Numerical tolerance bands should be based on clear system reliability criteria and not some arbitrary tolerance band. For example, maximum voltage limits should be based on equipment ratings at that point in the system. 3. Ref. "unit drifts out of schedule," on p.9 it is the system that is drifting, not generation units. 4. The statement on p.10, "This industry divide is not addressed in the pro forma standard presented today,". The SDT is encouraged to follow through on AVR paragraph under the VAR-002 section by pursuing full industry review of the White Paper as required by the Standards Process Manual, section 11. 5. While there is a sentence in the measure that states it is clearly the generator's discretion as to whether they monitor (presumably control) low side or high side to demonstrate compliance, we believe that there is still a substantial amount of language in the Standard and the Whitepaper that would tend to cloud that by implying that a generator should monitor high side for compliance if you have high side equipment installed; in other words, the monitoring/control point is based on current installed equipment. 6. Additionally, the Whitepaper does nothing to shed light on whether generators should make manual moves to reactive output (by changing the AVR low side set-point) without explicit direction from the TOP which leaves the compliance application open for interpretation.
Yes
Comments: See question 2 comments above. VAR-001-3 allows the TOP to determine the appropriate voltage schedules and tolerances for that TOP's area for the reasons stated in the White Paper under the VAR-001 section. Why does VAR-002 not allow the TOP to determine the corresponding time requirement? We believe that the prescriptive time requirement in VAR-002 may cause conflicts with R4 of VAR-001 such that system requirements and different control areas may require different notification and therefore will be problematic for system and plant operators. The TOPs are familiar with their systems and will issue voltage tolerance bands based on their system needs. Therefore, it is appropriate for the TOPs to establish the associated time frame for their tolerance bands based on their system needs. That is, the time frame should be linked to the tolerance band. If the voltage tolerance is reliability based the TOP with the RC should be able to establish a corresponding time tolerance for deviations from the scheduled voltage. No reliability gaps should exist if both voltage tolerance band and corresponding time frame are reliability based rather than arbitrarily established. It is imperative that the TOPs provide realistic voltage tolerances and time frames that are 1) practical for both system operators and generator operators who have many duties related to system and plant reliability and safety, and 2) will not result in administrative burdens due to unnecessary notification and possible violations for deviations in voltage schedule that do not pose a BES reliability concern. Further, it appears that this standard has been written with the assumption that generators can monitor and directly control transmission bus voltage. Generation design standards have been that plant voltage regulators regulate the generator bus and having operators being able to see grid voltage has not been a standard. The responsibility for monitoring transmission class voltage has been a transmission operations function and taking action to makes changes requires a wider system view that the generation plants will ever have. This is what is reflected in version 5 of the Functional Model, which states that the GOPs in Real Time 10. Provides Real-time operating information to the Transmission Operators and the required Balancing Authority. 11. Adjusts real and reactive power as directed by the Balancing Authority and Transmission Operators.
The SDT is encouraged to follow through on AVR paragraph under VAR-002 by pursuing full industry review of the White Paper as required by the Standards Process Manual, section 11. The comments expressed herein represent a consensus of the views of the above named members of the SERC Generation Subcommittee (GS)only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
Florida Municipal Power Agency
Frank Gaffney
No
Yes

FMPA appreciates the efforts of the ad hoc team; but, the ad hoc team missed many opportunities to reduce duplication of the VAR standards with other standards (e.g., TOP standards, FAC-011, FAC-014). Consequently, FMPA is recommending a Negative vote. VAR-001-4, R1 is Duplicative of FAC-011 and the TOP-004 Standards This requirement as drafted is duplicative of existing TOP-004-2: “R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations.” The Project 2007-03 SDT that revised the TOP standards found this requirement administrative in nature and eliminated the need for policies and procedures, mapping much of this requirement to the Purpose statement of the new TOP-001-2 Standard. VAR-001-4 should at least remain consistent with Project 2007-03 SDT’s intent and eliminate policies and procedures as administrative in nature. R1 as drafted is also duplicative of FAC-011, System Operating Limit Methodology in the Operating Horizon: Proposed VAR-001-4, R1, 1.1: “These documented policies or procedures shall include criteria used in system assessments. The criteria for the assessments shall include established steady-state limits, voltage stability limits and associated operating margins, and voltage schedules along with associated tolerance bands.” (emphases added) Existing FAC-011-2: “R2. The Reliability Coordinator’s SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits … R3. The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins …” (emphases added) Hence, R1 as drafted essentially requires developing and implementing policies and procedures to: a) Operate within SOLs. b) Operate to voltage schedules The only unique part of R1 that is different than FAC-011 is “voltage schedules along with associated tolerance bands”. Therefore, R1 should be boiled down to just the TOP or RC establishing, and the TOP operating to “voltage schedules along with associated tolerances bands” to eliminate duplication with other standards. In addition, FMPA questions whether the RC should establish these voltage schedules instead of the TOP. If neighboring TOPs establish different, uncoordinated voltage schedules, then at the boundaries between TOPs, voltage schedules may be difficult to maintain and there will be significant VAR flow between the TOPs with significant associated losses. Coordinated voltage schedules between TOPS should be required. This can be accomplished in two ways: 1) the RC develops the voltages schedules; or 2) the word “jointly” is reintroduced to R1 (the ad hoc team chose to eliminate the word “jointly” from the existing requirement) so that neighboring TOPs “jointly” develop a coordinated voltage schedule. VAR-001-4, R2 is Duplicative of TOP-002 and TOP-001 and should be Eliminated VAR-001-4, R2 requires the TOP to perform assessments (which is duplicative of TOP-002-3, R2 to develop a plan to operate) to ensure sufficient reactive reserves to maintain voltage stability. Voltage stability is a determinant of SOLs; hence, the standards already require TOPs to develop and to operate within SOLs, including SOLs determined by voltage stability limits (FAC-011, FAC-014, TOP-001-2 R7 through R11, TOP-004-2, TOP-007-0). VAR-001-4 also requires TOPs to direct action if needed; for which they already have responsibility under TOP-001. Hence, R2 as drafted is entirely duplicative of other requirements and should be eliminated. VAR-001-4, R5 is Duplicative of TOP Standards and should be Eliminated TOP-006-2 states: “R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use …. R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.” So, contrary to the ad hoc team’s assertion, R5, which requires the TOP to know the status of all reactive power resources, AVRs and PSSs on their system, is duplicative of TOP-006-2, R1 and R2 which do include Power System Stabilizers and voltage regulators (e.g., “status of rotating … reactive resources”). The Project 2007-03 SDT mapped this to the TOP-003-2 standard, R1, which states: “Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.” Hence, if the ad hoc team disagrees with the action of the Project 2007-03 SDT in generalizing the requirement to a generalized data request as opposed to the specificity of exactly what “data (is) necessary for it to perform its … Real-time monitoring” the ad hoc team seems to desire, then, the newly formed SDT for this VAR project should instead modify TOP-

003-2 to incorporate that specificity and not include this requirement in VAR-001-4. VAR-002-3, R2, 2.3 is Duplicative of TOP-001 and should be Eliminated The requirement is essentially for GOPs to follow a directive of the TOP; which is duplicative of TOP-001-2, R1 which states: "Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements." Hence, VAR-002-3, R2, 2.3 should be eliminated. If "directed" as used in the draft VAR-002-3, 2.3 is not intended to be from a Reliability Directive, then, clarification is required as to what "directed" means. VAR-002-3, R3 is Duplicative of TOP-003 and should be Eliminated VAR-002-3, R3 as drafted requires GOPs to inform the TOP of changes in status or capability from a reactive power perspective. This is very similar in nature to the GOPs' obligation to inform the TOP of the same from a real power perspective in TOP-002-2, R14. The Project 2007-03 SDT mapped this to TOP-003-2, R5 which states: "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data." It is expected that the TOP will require such data in TOP-003-2, R1, and the GOPs will need to respond in accordance with TOP-003-2, R5. If the ad hoc team disagrees with the action of the Project 2007-03 SDT in generalizing the requirement as opposed to the specificity of exactly what "data (is) necessary for it to perform its … Real-time monitoring" the ad hoc team seems to desire, then, the newly formed SDT for this VAR project should instead modify TOP-003-2 to incorporate that specificity and not include this requirement in VAR-002-3.
Individual
Kathleen Goodman
ISO New England, Inc.
Agree
IRC SRC
Individual
Nazra Gladu
Manitoba Hydro
No
Yes
(1) Manitoba Hydro believes that Power System Stabilizer (PSS) should not be included in the standard (R3) because they are not designed for, nor could they be operated in any way to maintain and/or control Network voltage (schedules). In particular: (a) PSS deals with power swings (oscillations) by adjusting the generator voltages through AVRs to add damping to the generator rotor oscillations. The outcome of this process is to provide more stable real power transfer. (b) PSS does NOT control the generator or network voltages, but instead affects them in a uncontrollable way. Moreover, PSS does not contribute to the voltage stability. (c) If PSS must be included in the scope of this standard, then Manitoba Hydro believes that other functions in the AVR such as overexcitation limit (OEL), under excitation limit (UEL) and voltage per hertz limit should be included as well since they all at some point will affect the generator voltages during periods of "normal" operation. (d) It is our experience that PSSs are sometimes out of service as a result of automatically shutting off based on design and operational criteria which may include below certain gate positions or loading levels. In modern designs, the PSSs are normally part of the excitation control system and there is no physical turn-on/off switch (even though our utility has always asked for switches for easy operation). Manitoba hydro believes that there is a lack of clarity in the standard as it pertaines to the need to/process of reporting this status, i.e. the function of PSS is automatically switched off/on (out-of or back-in-service) during normal operation. Manitoba Hydro believes that if a requirement of the PSS is to remain in the standard, then a formal interpretation on this situation is warented. (2) Please clarify that when Automatic Voltage Regulators (AVR's) or Power System Stabilizers (PSS) come out of service, the appropriate Reliability Coordinator, Transmission Operator and neighbors are to be

notified should they be impacted. Moreover, this must be documented and posted for other Transmission Operators and RC's to view.
No
(1) Effective Dates, VAR-001-4 and VAR-002-3 - replace the words " Board of Trustees approval " with " Board of Trustees' approval " for consistency with other standards. (2) General Comment - replace " Board of Trustees " with " Board of Trustees' " throughout the applicable documents/standards for consistency with other standards.
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
Yes
The standards already require coordination. If the TOP is not being provided enough "cooperation" from the GOPs in their footprint, then there is a need for stronger internal documents to achieve the necessary level of cooperation. While the standard states they must coordinate, it does not provide to what extent. One solution may be to compensate VAR output as well as MW output for the GOPs. As it pertains to VAR-002-3, the last sentence of R3, should state "…..no need to NOTIFY the TOP", in lieu of "call the TOP." This consistency would be appreciated.
No
The standards already require coordination. If the TOP is not being provided enough "cooperation" from the GOPs in their footprint, then there is a need for stronger internal documents to achieve the necessary level of cooperation. While the standard states they must coordinate, it does not provide to what extent. One solution may be to compensate VAR output as well as MW output for the GOPs.
Individual
Scott Langston
City of Tallahassee
No
No
No
The standards already require coordination. If the TOP is not being provided enough, "cooperation" from the GOPs in their footprint, then there is a need for stronger internal documents to achieve the necessary level of cooperation. While the standard states they must coordinate, it does not provide to what extent. One solution may be to compensate VAR output as well as MW output for the GOPs. As it pertains to VAR-002-3, the last sentence of R3, should state "…..no need to NOTIFY the TOP", in lieu of "call the TOP." This consistency would be appreciated.
Individual
Bill Fowler
City of Tallahassee
No
No

No
The standards already require coordination. If the TOP is not being provided enough, “cooperation” from the GOPs in their footprint, then there is a need for stronger internal documents to achieve the necessary level of cooperation. While the standard states they must coordinate, it does not provide to what extent. One solution may be to compensate VAR output as well as MW output for the GOPs. As it pertains to VAR-002-3, the last sentence of R3, should state “…..no need to NOTIFY the TOP”, in lieu of “call the TOP.” This consistency would be appreciated.
Group
Duke Energy
Michael Lowman
No
Yes
Duke Energy suggests the SDT consider using the NERC defined terms of Operating Plan, Operating Process or Operating Procedure instead of “policies or procedures” in Requirement 1 to provide clarity and consistency. R1.2 and R1.3 should be revised and consolidated to read, “ Upon request, the TOP shall provide a copy of these documented Operating Plans, Operating Processes, or Operating Procedures to adjacent Transmission Operators and its Reliability Coordinator. “ Duke Energy recommends the SDT determine the correct NERC defined Time Horizon necessary for all requirements in VAR-001-4 as “Operations” is not considered a valid NERC defined time horizon. Measure 1 would have to be modified if “Upon request” is accepted by the SDT. Duke Energy suggests the following for Requirement 2 1. R2 should be changed to, “Each Transmission Operator and Reliability Coordinator shall perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1. 2. R2.2 should be changed to, “As a result of the assessments, each Transmission Operator shall ensure that sufficient reactive resources have been scheduled are available to meet acceptable day-ahead voltage limits identified in Requirement R1. Sufficient reactive resources may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; and controllable load. Duke Energy seeks clarification on the term “real-time event” used in M2. What was the criterion considered to constitute a “real-time event”? The concern is that an auditor could consider a 1kV voltage deviation a “real-time event”. This type of voltage deviation has no impact to the reliability of the BES. The SDT should consider using alternative language that is more specific. Duke Energy suggests alternative language for VAR-001-04 R4.1 and VAR-002-3 R.1. Per the NERC Compliance Analysis Report of the VAR-002, it is stated that there are three widely-used AVR modes for generators: AVR- automatic controlling voltage mode, AVR-VAR mode, and AVR-power factor mode. Duke Energy is aware of a number of generating facilities that are not equipped with an automatic voltage regulator, thus the pro-forma standard should be revised to include other known AVR modes. Duke Energy suggests the following language: VAR-001-4 R4.1 should read: 4.1. The Transmission Operator shall provide the voltage or Reactive Power schedule and tolerance band to the associated Generator Operator and direct the Generator Operator to comply with the schedule in one of three AVR modes (AVR-automatic controlling voltage mode, AVR-power factor control mode, or AVR-VAR control mode) as determined to be appropriate by the TOP. R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in one of three AVR control modes specified by the Transmission Operator (AVR-automatic controlling voltage mode, AVR-power factor control mode, or AVR-VAR control mode)unless 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-up1 or shutdown2 • That the generator is not being operated in the TOP-directed AVR control mode for a reason other than start-up or shutdown. In VAR-002-3 R4, Duke Energy suggests removing auxiliary transformers from the standard. Auxiliary transformers are not used to control MVars for reliability purposes. In VAR-002-3 R5, Duke Energy suggests inserting the phrase “mutual assent” into the language of R5. The standard language should read as follows: R5. “After consultation and mutual assent with the Transmission Operator regarding necessary step-up transformer tap changes, …”

Yes
Duke Energy suggests extending the timeframe a GOP must notify its TOP of schedule drift to 30 minutes to allow time for recognition of the problem, assessing corrective action needed, and contacting the TOP when required. Regarding VAR-002-3 R2.1, the start time that a generator “drifts out of schedule” (i.e. is considered to have drifted out of schedule), is dependent upon the method used for monitoring the voltage. Does the clock start based upon the first scan that the generator is outside the voltage schedule, and stop upon the first scan that the generator is back within the voltage schedule? If not, how long of a period must a generator be back within schedule to reset the clock? Can the Transmission Operator define the criteria for measurement when the voltage schedules are provided? For example, can the TOP indicate that a generator is considered outside its voltage schedule when the clock-minute average voltage is outside the schedule? No matter of the data used for measuring voltage against the voltage schedule (scan-rate, clock-minute, rolling ten-minute average), is a generator considered back within its voltage schedule (clock stops) based on the same measurement to contact the TOP? Duke Energy suggests clarifying the term “capability change” in the White Paper revision. There is considerable confusion about the time requirement and it is not clear that these are applicable to the AVR status question or the capability change question. It may make sense to separate these two requirements to allow better clarification. Duke Energy suggest adding the words “or maintain any documentation” after TOP in the R3 sentence. The rewording should read as follows: “If the status has been restored within the first 15 minutes of such change, then there is no need to call the TOP or maintain any documentation” Duke Energy suggests rewording Measure 3 as follows: “The Generator Operator shall have evidence it notified its associated Transmission Operator as required in Requirement 3. If the status has been restored within the first 15 minutes, no call is necessary.”
Individual
John Bee
Exelon and its' affiliates
Yes
As NERC representatives pointed out in recent webinars, one goal of many of the existing standard development projects is to seek a steady state for applicable standards. In order to avoid iterative development projects, the SARs should accommodate all known issues and/or recommendations. The recently issued Independent Experts Review Project cites some requirements within VAR-001 and VAR-002 for attention. The scope of the SAR should include assessment and resolution of the Independent Expert Review Report recommendations. Additionally, to the extent related, the recently submitted risk assessment by the RISC should be considered when developing the scope of SARs. Question 4 below requests input on specific issues acknowledged are not currently included in this project. More detail is below, but Exelon supports addressing all known issues, not just the FERC directives, at this time. In addition, Exelon supports the concept of developing Compliance Guidance concurrently with the Standard development because it makes sense to develop audit explanations and tools while the intent and information is fresh and under development. In addition, this is very useful for Registered Entities to understand how compliance will be judged. However, it is not clear how development of Compliance Input is to be conducted. The Compliance Input should evolve as the Standard language evolves through the standards development process and must ultimately reflect the actual language in the final, approved standard. Understanding that no ballot is associated with Compliance Input, it would be very useful for NERC to post Compliance Input with a separate comment form for stakeholder input. Some of the project SARs cite development of an RSAW. Stakeholder Review and comment on RSAWs and Compliance Input prior to the final ballot of a proposed standard will be mutually beneficial.
Yes
The VAR white paper discusses VAR-002 Requirement R2 and provides a discussion on notifications regarding adherence to a voltage schedule. Specifically, this paper mentions instances where the unit may not be able to return to schedule when it has encountered an operating limit, or when a system event is pulling the unit out of schedule; however, this project does not address issues where the TOP (as may be delegated to the TO) provides an unrealistic voltage schedule that is difficult if at all possible to maintain by the Generator Operator. The white paper evaluates the need for the TOP and

GOP to agree to a voltage schedule but dismisses that concept as it could create “disputes between the parties as to what the appropriate voltage schedule should be for a unit”. In our opinion, VAR-002 should provide a vehicle for a GOP to challenge what they may perceive as an unrealistic schedule if that schedule is unmanageable or challenges the physical operating capability of the generating unit. Exelon suggests that a formal notification to the TOP/TO with a technical justification be required to ensure that this challenge not be abused by the GOP. We believe it is reasonable to allow the generator to monitor the high side or the low side of the generator step up transformer; however, the TOP should align their voltage schedule to match the GOP chosen monitoring equipment or agree on the conversion factor. There is not a one for one conversion between grid voltage and terminal voltage and both parties should agree on the conversion to avoid any future audit or implementation issues. Further to the the specific language in proposed VAR-002, R2, the statements do not seem to track with the stated intent. It appears that a GOP is to notify a TOP within 15 minutes concurrently with being out of the schedule for 15 minutes. Should the language read: “…each Generator Operator shall notify its associated Transmission Operator within 30 minutes when both of the following conditions are met: …” VAR-002, R2.3. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met. Suggest that “the schedule” be replaced with “the modified Voltage Level” since a request to move Voltage is not really a new “schedule” it is just a temporary change. The Implementation Plan for VAR-001-4 and VAR-002-3 requires the new Standard revisions to be implemented the first day of the first calendar quarter after applicable regulatory approval. This is not sufficient time to allow generating units to implement training of operators and procedural changes necessary to implement the proposed changes to notification requirements. Suggest at least a 6 month implementation period following regulatory approval. Note that as written in the proposed implementation plan, the “first calendar quarter following approval” does not guarantee even the cited timeframe of 3 months (i.e. if approved in March 2014, it becomes effective April 1, 2014). To accommodate a six month implementation period the language must mark time in months. For example the language should read: “this standard shall become effective on the first day of the seventh month after applicable regulatory approval…” The current draft does not have any tolerance at all and starts a time requirement regardless of the deviation from the voltage band. Why is this Standard requiring a time requirement for notification to the TOP when each voltage schedule, tolerance, and voltage band is different for each generator based on size, location, impact to the system and the TOPs preference for operating its system?. The voltage schedule, tolerance band, and notification requirements should be left to the discretion of the TOP. The revised Standard VSL should include a percentage value associated with an excursion outside of the voltage schedule. If the Standard moves forward without any evaluation of the magnitude of deviation from the voltage schedule, then there should be some consideration of this in the associated VSLs. Finally Exelon suggests that the Compliance Section 1.2 Evidence Retention for VAR-002-3 should read the same as for VAR-001-4.
Yes
If the operator takes the time to trouble shoot, make repairs or makes attempts to get the AVR or If the operator takes the time to trouble shoot, make repairs or makes attempts to get the AVR or PSS back to automatic, the operator limits the time available to notify the TOP that the AVR or PSS is not in auto. Exelon recommends that the time for notification be increased to allow for the operator to trouble shoot and make a determination that the AVR/PSS cannot be put back in auto. Additionally, Exelon would like the standard to specify that AVR/PSS status indication, if installed, via SCADA will satify the notification requirement.
As stated above, this project does not address issues where the TOP (as may be delegated to the TO) provides an unrealistic voltage schedule that is difficult if at all possible to maintain by the Generator Operator. Throughout the white paper and this comment form there is the common theme of addressing a “reliability gap”. In the cases of generator who are given an almost impossible job of attempting to adhere to an unrealistic voltage schedule, there is frustration on the operator’s part or constant attempts to adjust voltage that has little or any impact on the system. In the technical white paper this is classified as a “minority issue” however in our opinion this is an issue that definitely warrants attention therefore Exelon feels that it is appropriate to expand the scope of this project to address this and all known issues relevant to the Standards.
Individual
dmason
HHWP

No
Yes
"The Transmission Operator shall know the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. [Violation Risk Factor: Medium] [Time Horizon: Operations]" does not allow for a TOP to specify its own information requirements for ensuring that its portion of the BES is operated reliably.
No
Yes it is appropriate to address the coordination between GOP and TOP in this project
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) We are concerned that the informal development process that was originally contemplated has gone off course. The original plan that was announced to industry was to have an informal development team create a proposal for a standard, which would then pass the preliminary work to a formal standard drafting team to continue the development process. This is not what has occurred. The informal development process should not circumvent the NERC Rules of Procedure. (2) We question the value in posting the draft standard with the SAR. What good is the SAR posting if a standard has already been developed? This gives the impression that the Standards Committee has already determined the need for the standard and eliminated the opportunity for industry stakeholders to provide feedback. It seems unnecessary to comment on the SAR at this point because it appears that it was drafted in tandem with the pro forma standard. We urge NERC to pay close attention to its Rules of Procedure and the Standard Process Manual to avoid deviations and setting precedent that could be challenged in the future. (3) We are also concerned that the standards process manual was not followed correctly regarding the selection of the drafting team. The nomination period began after the draft standard was posted, which clearly shows the ad hoc team developed the draft standard instead of satisfying the activities it was charged with by vetting the issues of the VAR standards with industry. The initial draft standard should be the work of the appointed standards drafting team. We doubt that there was sufficient time for the new drafting team members to thoroughly review and agree with the language in the initial posting. The method of developing the initial draft should comply with the NERC Rules of Procedure and we are concerned that a bad precedent is being set.
Yes
(1) Requirement VAR-001-4 R1 is redundant with FAC-011-2 and FAC-014-2 and, thus, meets paragraph 81 criteria. FAC-014-2 R2 requires each TOP to establish SOLs for its transmission system that is consistent with the RC SOL methodology. FAC-011-2 R2 compels the RC to develop a SOL methodology that requires SOLs to consider voltage, thermal, and stability limits (including voltage) and demonstrate that the BES remains stable (transient, dynamic and voltage) during pre-contingent (R2.1) and post-contingent (R2.2) conditions. FAC-014-2 R6 compels the Planning Coordinator to identify which Category C (multiple) contingencies from TPL-003 that result in stability limits (including voltage) and to communicate the list of Category C (multiple) contingencies along with the stability limits to the RC. FAC-011-2 further compels the RC to establish a process for identifying which stability limits associated with multiple contingencies identified by the Planning Coordinator are applicable in the operating horizon within its SOL methodology. FAC-014-2 R5.2 compels the TOP to communicate its SOLs to its RC and TSP and FAC-014-2 R5.1 compels the RC to communicate the SOLs to neighboring RCs and other TOPs among a list of other entities. Finally, existing TOP-002-2.1b R10 and proposed TOP-002-3 R2 require the TOP to operate within SOLs. Thus, the combination of FAC-011-2 and FAC-014-2 compel the establishment and communication of SOLs within the TOP footprint that already consider the items such as steady-state voltage limits and voltage stability limits compelled in proposed VAR-001-4 R1 and its subparts and TOP-002 compels the TOP to operate within those SOLs. Please strike R1 in its entirety since it is clearly redundant. If the drafting team

does not strike the requirement, we ask that technical justification be provided to explain why the requirement should remain and why the redundancy is necessary. (2) If the standards development team determines there is a technical distinction that would justify why requirement VAR-001-4 R1 remains in the standard, we suggest combining parts 1.2 and 1.3 for simplicity since they both are about providing documentation. (3) We are concerned with the statement in the rationale box for R1 that this “requirement will allow each Transmission Operator (TOP) to establish its own policies and procedures”. This statement implies that the TOP cannot create its own voltage policies and procedures without this requirement. This is simply not the case. All TOPs already have their own policies and procedures for voltage so the requirement is not necessary to “allow”. Since there is not a specific requirement to have such policies and procedures, some may not be documented to the level necessary to demonstrate compliance but they do exist. Please modify the rationale box to state that it will “compel” or “require” and not “allow” policies and procedures. (4) While we believe VAR-001-4 R1 is redundant with other standards as stated above, we recommend removing “establish” and “Reactive Power flow (Mvar flows)” in R1 if the requirement persists. Both are redundant and, thus, superfluous. First, you cannot monitor “voltage levels… within limits” without establishing such limits. Furthermore, the requirement to establish limits is clear in Part 1.1. Second, you cannot control voltage levels with controlling Reactive Power flows. Thus, it is redundant in the requirement. (5) If VAR-001-4 R persists, please change “Mvar” to “MVAr” in requirement R1. It is actually the correct way to document megavolt amperes reactive. (6) VAR-001-4 M1: The measure contradicts itself. It states web postings as valid evidence but then states that posting a copy of the policy or procedure on a public website is not sufficient. Is it valid evidence or not? (7) VAR-001-4 R2 is redundant with currently enforceable TOP-002-2.1b R10 and R11. R11 already requires the TOP conduct seasonal, next-day, and current-day studies or assessments to determine SOLs and R10 requires the TOP to operate within those SOLs. Remember from our response in bullet (1) that FAC-011-2 and FAC-014-2 collectively require those SOLs defined by the TOP to consider pre-contingent and post-contingent voltages and voltage stability per the RC SOL methodology. Furthermore, some of the contingencies must include Category C contingencies that cause stability issues. There are similar requirements in the proposed TOP-002-3 to perform an assessment and operate within SOLs. We suggest revising R2 to remove this overlap. (8) We disagree with including the list of reactive devices in VAR-001-4 R2. It is simply not needed and is not complete either. If a TOP is not aware of the types of tools and equipment it has available to control voltage, there are more serious issues surrounding the TOP’s certification. Furthermore, it might create the unintended consequence of compelling load shedding to maintain a steady-state voltage limit. If the TOP must follow its plan in R1 to operate within steady-state voltage limits by operating “voltage regulation devices” (which includes load shed) in R2, wouldn’t the literal interpretation mean that load would have to be shed because a steady-state 94% voltage was below the typical 95% steady-state limit. Obviously, this would be bad for reliability. A registered entity should never be put in a position of having to choose between compliance and reliability. (9) VAR-001-4 M2 refers to studies while VAR-001-4 R2 refers to assessments. If this requirement should persist contrary to our arguments presented in point (7), we suggest using NERC Glossary Term Operational Planning Analysis (OPA). An assessment is a vague term that has several meanings and no time boundaries associated with it. For example, "assessment" is used in the TPL standards, which mean it could go out 10 years. While we understand there would be no reasonable expectation for a TOP to perform an assessment 10 years out, there could be inconsistent compliance applications because one auditor believes an assessment should cover the next day and another believes it should cover the next week. OPA is specific and bounded by time. Furthermore, use of this term would make the standard consistent with IRO-005-4, IRO-008-1, IRO-010-1a, TOP-001-2, TOP-002-3, and TOP-003-2. (10) VAR-001-4 R3 should be modified to state the TOP shall specify the criteria that will exempt generators from maintaining the voltage schedule. The TOP is not the enforcement authority and cannot exempt another responsible entity from compliance. We are concerned the language used will not be approved by FERC and result in a subsequent directive. (11) Part 3.1 of VAR-001-4 would appear to meet the paragraph 81 criterion on reporting. The criterion states that the requirement should be retired if it “obligates responsible entities to report to a Regional Entity, NERC, or another party or entity”. Clearly, the GOP would be “another party or entity”. The GOP should be able to simply self-determine from the criteria provided by the GOP that it satisfies the criteria. The TOP will be able to see if the GOP is following the voltage schedule from the telemetry. If there is a question, the TOP would call the GOP. (12) While the language in VAR-001-4 R4 is clear that the TOP must have criteria for granting exemptions, the associated language in VAR-001-4 Measure M4 states that the “temporary exemptions may be provided". Please modify the language in the measure to be clear that the temporary exemptions will be provided if the criteria are met. Otherwise, the measure sounds like the TOP has discretion in granting the temporary exemptions. (13) VAR-001-4 R4 should be modified to require the TOP to only provide a voltage schedule to generators that are capable of controlling voltage. As it literally reads now, the TOP must provide a voltage schedule "to be maintained by each generator". This would include even small generators that simply do not have the size to control voltage. As an example, a 1 MVA generator connected to a 138 kV bus should not be expected to control to a voltage schedule because it simply will never be able to maintain the voltage schedule. One potential solution to address this problem is to insert BES before generator in the requirement. Once the new definition is in effect, it would be clearer that voltage schedules must be provided only to generating units 20 MVA or greater in size and or aggregate generating plants 75 MVA or greater in size. (14) It is unnecessary to require the TOP to direct the Generator Operator to comply with the voltage schedule with the AVR in voltage control mode in VAR-001-4 Part 4.1. It is redundant with VAR-002-3 R2 which compels the GOP to follow the voltage schedule. If drafting team feels the "directive" language is necessary in VAR-001-4 Part 4.1, then VAR-002-3 R2 should be removed because it would be redundant with TOP-001-1a R3 (existing) and TOP-001-2 R1 (pending regulatory approval). Both require the GOP to follow the directives of its TOP. (15) Contrary to the rationale box for VAR-001-4 R5, this requirement is clearly redundant with TOP-006-2 R1 which requires the TOP to know the status of all generation and transmission resources available for use and VAR-002-3 R3 which requires that GOP to notify the TOP of a change in the status of the automatic voltage regulator (AVR) and power system stabilizer (PSS). Since voltage control is one of the primary responsibilities of the TOP, it can be safely assumed that a transmission resource would have to include reactive power resources. Thus, the VAR-001-4 R5 is at least partially redundant with TOP-006-2 R1. How would a generation resource not include the status of the AVR and PSS? The drafting team appears to be interpreting TOP-006-2 R1 outside of the standards development process since interpretation of TOP-006-2 R1 was not included in the scope. If the drafting team does not believe an AVR or PSS is covered in TOP-006-2 R1, the appropriate course of action would be to submit a request for interpretation of TOP-006-2 R1 to verify the interpretation. If industry would disagree through the ballot process, then the interpretation would clearly obviate the need for the requirement for the remaining parts of the requirement. Finally, we can understand why the drafting team may want to emphasize reporting changes in status of the PSS and AVR but VAR-002-3 R3 compels the GOP to report the changes to the TOP already. Please strike VAR-001-4 R5 since it clearly meets the P81 criteria regarding redundancies. (16) Please clarify VAR-001-4 R6 that the TOP must consider the safety, equipment, statutory, and regulatory requirements on the GOP when specifying GSU transformer tap changes. (17) The compliance section needs significant revision. This section does not look like a final standard and is missing much of the boiler plate language. (18) VAR-001-4 VSLs: Overall the VSLs need significant work and do not look like final VSLs. For example, the Severe VSL for R2 mentions that the TOP does not perform assessments and, therefore, does not have policies and procedures implemented. R2 does not require policies and procedures. R1 does. The same Severe VSL also has a vague statement at the end stating "a lack of real-time operation," which is also classified as Severe. How does this relate to the requirement? The VSLs for R4 are inconsistent. One mentions tolerance bands and the other does not. Furthermore, failure to provide a voltage schedule to a 1000 MVA generator on a 500 kV voltage constrained line has a much greater impact on reliability than failing to provide a voltage schedule to 25 MVA generator on a 138 kV line. The former would miss more of the requirement than the latter. The bottom line is that there is an opportunity to provide more graduated VSLs than two levels. Four should be provided for R4. (19) VAR-002-3 R2 will be problematic for some GOPs because it does not reflect the characteristics of the voltage schedule provided by some TOPs. For example, some TOPs provide an hourly average voltage schedule to avoid the need for notification for every time the GOP drifts out of schedule. How would R2 be applicable in this situation? Would it only apply for the first 15 minutes of each hour looking back at the last hour? Please modify the requirement accordingly to address this issue. (20) The VSLs for VAR-002-3 R2 are too severe. Failure to provide an explanation to the TOP for failure to provide an explanation to modify voltage per Part 2.3 should be a Lower VSL not a Severe VSL. The TOP will have telemetered voltage values and will be able to see that voltage has not been modified. Thus, the TOP will be aware of the issue and will be able to call the GOP to find out what is happening or make other arrangements to modify voltage. (21) We suggest that the VAR-002-3 R2 should use different language than "as directed by the Transmission Operator". Compliance personnel may read this to mean this is a directive. If this is directive, then TOP-001-1a R3 would also apply. In essence, the language creates the opportunity for double jeopardy because failure to follow the voltage schedule

would be a violation of VAR-002-3 R2 and could be viewed as a violation of TOP-001-1a R3 for failure to follow the directive. Similar issues exist in the subparts of the requirement. (22) The VSLs for VAR-002-3 R4 appear to be intended for VAR-002-3 R2. (23) The VSL for VAR-002-3 R5 states that a technical justification must be provided for why the GOP did not implement that tap changes. No such requirement exists in the standard. The GOP could provide a safety or statutory reason for not changing the tap which are not technical justifications. Please revise the VSL accordingly.
Yes
We believe the notification should not be required until one hour after the generator has drifted from the voltage schedule or the PSS or AVR has changed status. This will give ample time for the generator to make adjustments to return to the voltage schedules, return the PSS or AVR to service or determine that it will be unable to return the voltage schedule or return the PSS or AVR to service. Then the GOP can notify the TOP. Furthermore, the TOP will be monitoring voltage and can call the GOP in the interim if they need an update on why the voltage schedule has drifted. This will also allow ample time for the TOP to switch reactive devices should they be needed which will help return the generator to voltage schedule and increase its dynamic reactive reserve.
We have no specific additional recommendations beyond those provided in earlier questions. Thank you for the opportunity to comment.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
ATC doesn't have any recommended changes to VAR-001 R1. However, VAR-001-4, M1 states "the policies and procedures must detail how criteria for steady-state and voltage stability limits are used in the [TOP's] assessments …" [emphasis added]. This language should be modified to reflect the wording of the requirement, which only requires that the TOP's policies and procedures specify the criteria, not the manner in which the criteria is used in an assessment. A suggested change is: "the policies and procedures must detail the steady-state and voltage stability limits criteria to be used in the [TOP's] assessments of the system." VAR-001-4, R2 and its sub-requirements are duplicative of approved future standards TOP-001-2 R7 though R11 and TOP-002-3 R1 and R2. TOP-001-2 requires the TOP to identify and operate within SOLs and covers VAR-001-4, R2.1. The NERC definition of SOL includes both voltage stability and steady-state voltage limits. The argument that R2.1 is focused on directing reactive resources misses the point that the requirement is designed to ensure that the system is operated within SOLs. VAR-001-4 R2.1 specifies in detail what the TOP will be doing to ensure compliance with TOP-001-2 R9 through R11. TOPs should not be subjected to potentially violating two standards that cover the same ground. Similarly, TOP-002-3 R1 requires TOPs to have next-day assessments and TOP-002-3 R2 requires the TOP to develop a plan to operate within SOLs. The plan under TOP-002-3 R2 would, by necessity, include scheduling reactive resources, when necessary, to ensure SOLs will not be violated. If the comment above regarding VAR-001-4 R2 is not accepted by the ad-hoc team, the following comments on VAR-001-4 R2 should be considered: VAR-001-4, R2 does not specify "real-time and day-ahead assessments" as noted in the R2 rationale statement. The word "assessments" in R2 is not modified by any accompanying descriptor. R2 should be edited to add "real-time and day-ahead" prior to "assessments". VAR-001-4, R2.2 states that the list of options "is not limited to" the methods mentioned. However, given R2.1 specifically calls out load shedding and R2.2 does not specifically state this, it is likely that a future auditor will note this difference and state that load shedding is not acceptable under R2.2. Therefore, R2.2 should explicitly include load shedding, if necessary, as another acceptable tool in the day-ahead plan. VAR-001-4 R3.1 states that the TOP "shall notify the associated Generator Operator" but M3 states that the TOP is to have evidence showing that it notified "the associated Generator Owner". This discrepancy should be corrected. VAR-001-4 M3 places too high of a burden on the TOP for a GOP AVR issue. Specifically, the TOP is made accountable for tracking temporary exemptions granted to a GOP when the GOP calls to state that their AVR is no longer in automatic mode or is no longer controlling voltage. Since no standing exemption has been granted to the GOP (hence the phone call), the compliance obligation to show that an exemption was granted should rest on the GOP through VAR-002-3 R1 and/or R2. VAR-001-4 R4 seems to have a potential inconsistency between the

parenthetical statement and the balance of the requirement. It is suggested that R4 be rewritten and simplified as follows: “Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band at the interconnection point between the generator facility and the Transmission Owner’s facilities, or at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion, to be maintained by each generator.” Other than our comments on VAR-001-4 R4 noted in the preceding paragraph, we agree with and fully support the current wording of VAR-001-4 R4. VAR-001-4 R5 conflicts with VAR-002-3 R3/M3 because VAR-001-4 obligates the TOP to know the status of all AVRs and PSSs but VAR-002-3 does not obligate the GOP to report status or capability changes of AVRs and PSSs if the duration of change is less than 15 minutes. VAR-001-4 R5 should be clarified to state that the TOP is dependent on the GOP to report status of AVRs and PSSs. Suggested edits are as follows: “R5. The Transmission Operator shall know the status of: 1) all transmission Reactive Power resources in its system, and 2) automatic voltage regulators and power system stabilizers as communicated by the Generator Operators in its system.” VAR-001-4 M5 should read: “The Transmission Operator shall have evidence to show transmission Reactive Power resources are being monitored” since that is the language of the requirement.
Yes
See comment in response to question #2 above where 15 minute window in VAR-002-3 R3 conflicts with VAR-001-4 R5.
ATC believes a standard is not required to address this issue.
Group
DTE Electric
Kathi Black
No
No Comments
No
No Comments
No
No Comments
It is our opinion that any communication and coordination between the TOPs and GOPs that affects reliability should be included in the standard.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
ATC does not believe that placing both VAR Standards on one ballot is a good practice, and in fact, only VAR-001 is applicable to ATC as a TO/TOP. For future postings, please post as two separate balloted Standards. This can also create a conflict such that an entity can support one and not the other, resulting in a dilema as to vote affirmative or negative that would affect one or the other Standard negatively.
Individual
Brian Shanahan
National Grid Transmission Operations
Agree
NPCC Regional Standards Committee
Individual
Catherine Wesley
PJM Interconnection

No
Yes
Specific to VAR-001-4, PJM questions why the RC is included in the standard since the responsibilities to comply with all the requirements are with the TOPs actions. If there are no actions for the RC, PJM supports the RC being removed from the standard. Included in R1 is use of the term ‘establish’ specific to policies and procedures that are required to be implemented. PJM supports deletion of that specific word because there are several other standards which specifically address establishing methodologies, in turn, procedures and processes, that define voltage levels, reactive power flow, steady state limits and voltage stability limits. Those standards included TPL-001, 002 (footnote a, Table1), FAC-010-2.1 and FAC-011-2 (R1, R2, R2.2) and FAC-014-2 (R1, R2, R3, R4).
No
Individual
Diane Barney
New York State Dept of Public Service
Yes
It is premature to be voting at all for the standard at this point in the process. Two major pieces of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft standard.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC.
No
Yes
CenterPoint Energy appreciates the efforts of the informal development team in providing the industry the proposed language changes to the VAR Standards incorporating the remainng FERC Directives. CenterPoint Energy offers the following comments and proposed changes for consideration and discussion to better align the standard language to the functions of Transmission Operator and Reliability Coordinator as described in the NERC Reliability Functional Model Technical Document Version 5 in relation to the coordination and control of voltage. The Transmission Operator has policies to monitor and control static reactive devices under its range of vision and control only. The Transmission Operator also has policies for requesting reactive output from generation units already online for voltage control; however, the redispatching of generation for reliability purposes is the responsibility of the Reliability Coordinator. Since the Transmission Operator cannot control all of the generation, then the Transmission Operator is unable to perform a complete or valid Operational Planning Analysis and modify generation dispatch to maintain operational limits both steady state and dynamic. Furthermore, any maintenance outages on static reactive devices need to be reviewed and approved by the Reliability Coordinator. Also, it is unclear to the industry what kind of action is expected from the Transmission Operator based on the status of the reactive power resources since the Transmission Operator cannot dispatch other units to make up for lack of AVR or frequency control in a generator. It would seem to be crtitical for the Balancing Authority and Reliability

Coordinator to be notified of status or capability change on any generator Reactive Power resource. CenterPoint Energy recommends the requirements be modified as follows: VAR-001-4 R1. Each Transmission Operator shall have documented policies or procedures that are implemented to monitor voltage levels and reactive power flows (MVAR flows) and maintain the voltage within limits by controlling reactive devices under its purview or by directing online generation. R1.3 Each Transmission Operator shall provide a copy of its local documented policies or procedures to its Reliability Coordinator. R2. Each Reliability Coodinator shall perform assessments… R3. The Reliability Coordinator shall specify criteria… R3.1 In the event a Reliability Coordinator approves a generator as satisfying the criteria, it shall notify the associated Transmission and Generator Operator. R4. Each Transmission Operator, in coordination with the Reliability Coordinator, shall specify a voltage or Reactive Power schedule and tolerance band at the interconnection point between the generator facility and the Transmission Owner's facilities to be maintained by each generator. R4.1 The Reliability Coordinator shall provide the voltage or Reactive Power schedule to the associated Generator Operator. The Transmission Operator shall direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). R5. The Balancing Authority and the Reliability Coordinator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers. R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Owner, in coordination with the Reliability Coordinator, shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. VAR-002 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) unless the Generator Operator has notified the Reliability Coordinator of one of the following…
No
Individual
Steven Mavis
Southern California Edison
Yes
SCE commends the drafting team on the work that it has done to address the FERC Order 693 Directives to modify VAR-001 and VAR-002. The draft standards are productive starting points for further clarification and refinement. Additional clarification is required before SCE can support the standards, for example, in VAR-001-4, Requirement 1.1, the use of the term "system assessment" is vague and ambiguous. The standards drafting team should provide further precision in explaining the intended meaning of this term.
Yes
The draft standards are productive starting points for further clarification and refinement. Additional clarification is required before SCE can support the standards, for example, in VAR-001-4, Requirement 1.1, the use of the term "system assessment" is vague and ambiguous. The standards drafting team should provide further precision in explaining the intended meaning of this term.
No
SCE commends the drafting team on the work that it has done to address the FERC Order 693 Directives to modify VAR-001 and VAR-002. The draft standards are productive starting points for further clarification and refinement. Additional clarification is required before SCE can support the standards, for example, in VAR-001-4, Requirement 1.1, the use of the term "system assessment" is vague and ambiguous. The standards drafting team should provide further precision in explaining the intended meaning of this term.
Group
IRC/Standards Review Committee
Gregory Campoli

Yes
We do not think the proposed requirement in VAR-001-4 which now includes RC as a Responsible Entity adequately addresses the directives. Please see our comments (b) under Q2.
Yes
VAR-001-4 a. It is unclear on the main objective and the target reliability outcome of Requirement R1, and the intent of the proposed changes in relation to the directive in P. 1868 in Order 693. We interpret R1 to require a TOP to have documented policies or procedures in place that can be implemented to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits as defined in Parts 1.1 to 1.3. However, Part 1.1 requires that the policy/procedure shall include criteria used in system assessments. It is unclear as to what “system assessments” means? Does it mean assessments of the TOP area’s reliability performance with respect to the voltage levels and Mvar flows and any limits (SOLs, IROLs, reactive capability)? Or does it mean the system assessment that yields the “limits” (SOLs, IROLs, reactive requirements, etc.) which provide the target and guideline for the establishment, monitoring, and control of voltage levels and Mvar flows? It is also unclear as to what the “criteria of the assessments” means in the second sentence of Part 1.1, especially in relation to “established steady-state limits, voltage stability limits, etc. if the answer to the above question is that the assessments were meant to yield the “limits”, then there is a confusion as to what limits are intended to be developed in relation to the “established” limits. In Order 693, P. 1868, FERC directs the ERO to modify VAR-001-1 to include more detailed and definitive requirements on “established limits”. However, it is unclear what this directive really means. Does it mean more details and definitive requirement on stipulating voltage and reactive requirements with respect to established limits (SOLs, IROLs, voltage level, etc.) or does it mean more details on limits (boundaries) of the interconnection voltages as implied by Requirement R8 of the existing VAR-001 standard? Requirement R1 does not provide this clarity since Part 1.1. refers to “established steady-state limits, voltage stability limits”, which is different than the “established limits” presented in the R8 of the existing VAR-001 standard. It is our understanding that as a general practice, a TOP will assess if there exists any reliability concerns that can be caused by voltage levels and instability to develop operating limits (SOLs or IROLs) to ensure reliable operations. The operating limits may be expressed in voltage level, pre and post-contingency power flow level, reactive support requirements or any combination of the above. The operating limits so established will provide a linkage between the SOL, voltage level and reactive power capability/reserve requirement either explicitly or implicitly. System Operators will monitor the key parameters including voltage level, power flow level and reactive power flow/reserve/capability to meet the SOL boundary conditions. Requirement R1 as presented does not provide any clarity as to what is it that in the practice that a TOP is required to meet. Requirement R1 as presented is unclear on its objective and the exact actions required of the Responsible Entity as there are a number of “criteria” and “limits” in the main requirement and its Part 1.1 that are confusing and subject to different interpretation. R1 as presented will leave a Responsible Entity not knowing what it needs to do to meet Requirement and its reliability objectives. We suggest the SDT to revise R1 and its parts to clarify its intent, especially on the who, the specific actions and expected outcome according to the results-based principle and guideline. Note that with respect to Part 1.1, Measure M1 asks for evidence that proves voltage is currently being monitored. Such evidence may include, but is not limited to: 1) proof that points are telemetered, 2) alarms are functioning, and 3) during events of low or high voltage the policies and procedures are being followed to respond to control voltage levels. These examples of evidence do not reflect the scope and depth of R1 and Parts 1.1 (the criteria and the assessment parts). We also suggest the drafting team review TOP-002 Rquirements R1, R8 and R10 as they relate to voltage limits. R1 obligates us to have plans to meet system conditions, similar to the VAR-001 R1. R8 requires us to meet voltage and reactive limits, R10 requires us to meet all SOL’s and IROL’s which are inclusive of voltage steady state and stability limits. The drafting team also needs to resolve the use of the term ‘establish’ as it relates to FAC-014 which requires us to establish SOL/IROL’s that include voltage limits. b. FERC directive 1855 directs NERC to include Reliability Coordinator as applicable entities and include a new requirement(s) that identifies the reliability coordinator’s monitoring responsibilities. In the Informal Consideration specific to this directive presented in the White Paper, it is indicated that: “Although some entities in Texas provided feedback that certain RCs perform functions equivalent to a TOP, the informal development group did not expand VAR-001 to give parity to TOPs and RCs.” R2 as presented appears to go beyond the FERC directive that RC be

included to be assigned the "monitoring responsibility" as R2 now requires the RC to "….perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1". The inclusion of RC in this requirement is also inconsistent with the view presented in the Informal Consideration with respect to parity between TOPs and RCs. Parts 2.1 and 2.2 stipulates a number of tasks for the TOPs with respect to operating or directing the real-time operation of devices necessary to regulate transmission voltage and reactive flow, and to ensure that sufficient reactive resources have been scheduled to meet acceptable day-ahead voltage limits identified in Requirement R1. These tasks do not involve the RC. It thus raises a question on the need for including RC in the main requirement when it is not required to take further actions to assure its assessment of "sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions" can be fulfilled in real-time operations. We believe the inclusion of RC in this requirement is inappropriate, or if there is a compelling reason to include the RC, then Parts 2.1 and 2.2 are insufficient to assure the RC's assessment can be supported in real-time operations. c. Requirement R2, Part 2.1 stipulates that: "Each Transmission Operator shall operate or direct the real-time operation of devices necessary to regulate transmission voltage and reactive flow necessary to regulate transmission voltage and reactive flow which may include…" We do not understand this requirement as it contains two sets of "necessary to regulate transmission voltage and reactive flow". If this is a typographical error, please correct it. d. We do not have any concerns or comments on R3 and R4 as presented, but suggest that their order be reversed since the exemption criteria (R3) should appear after the overarching requirements for GOs to maintain a voltage or Reactive Power schedule and tolerance band. e. R5: we suggest to change the word "know" to "monitor". This provides an active approach, which is appropriately reflected by the wording in Measure M4. f. In the Compliance Section, there is no requirement for the RC to retain evidence for Measure M2. Further, there is no requirement for the TOP to retain evidence for Measures M5 and M6. g. VSL for R1: There is no explicit requirement in R1 for the TOP to provide a copy of the assessment criteria to its RC or neighbor TOPs since the assessment criteria are supposed to be included in the policy or procedure document. The Low VSL thus serves no purpose whatsoever. Further, from the standpoint of meeting the intent of Requirement R1, there is little to no difference between having documented policies or procedures which do not include any of the elements stipulated in Parts 1.1 to 1.3, and having no documented policies or procedures at all. In the former case, the documented policies or procedures provide absolutely no value, and hence is it a total violation of the intent of R1. We suggest to remove the Low VSL and the High VSL, and keep the Moderate VSL and revise the Severe VSL to include the condition presented in the High VSL as an "OR" condition under the Severe VSL. h. VSL for R2: Throughout R2, there are not specific requirements for having policies and procedures implemented to have sufficient Mvars. R2 requires the TOP and RC to perform assessments on their respective areas in order to ensure sufficient reactive resources are available for scheduling to maintain voltage stability under normal and contingency conditions. Part 2.2 stipulates the requirements for scheduling reactive resources to meet the reactive requirements resulting from day-ahead assessments. Part 2.1 stipulates the requirement to operate or direct the real-time operation of devices necessary to regulate transmission voltage and reactive flow. While the Moderate VSL which address non-compliance with Part 2.2 and appears to be reasonable, the Severe VSL does not correspond to how Part 2.1 is presented. Further, the condition that "A lack of real-time operations is also severe." seems irrelevant to Part 2.1 when it comes to operating or directing the real-time operation of devices necessary to regulate transmission voltage and reactive flow. There can be no lack of real-time operations, but a TOP may totally ignore the operations or directing the operations of devices necessary to regulate transmission voltage and reactive flow. Finally, there is no VSL for the RC failing to meet R2. Hence, RC is assigned a responsibility but its compliance is not measured and there is no VSL to determine its non-compliance. i. VSL for R5: The conditions in the Moderate and High VSLs are irrelevant to the requirement. R5 requires a TOP to know (monitor) the status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. The Moderate VSL makes reference to a "stable area", which is totally irrelevant and out of context of R5. In the High VSL, the TOP not knowing "the status of important equipment in weaker areas that were identified in assessments as part of R1." are also irrelevant and out of context of R5. Finally, there is no Severe VSL. It begs the question on: what constitutes a total failure to comply with Requirement R5? j. VSL for R6: The Low VSL should have an "is", not an "are". Also, there is no Severe VSL and hence there is no condition to constitute a total failure to comply with Requirement

R6. VAR-002-3 k. Measure M2: A good part of M2 presents the scenarios where a Generator Operator may not be able to meet voltage schedule or comply with the TOP's directive, and how a GOP may mange the situations. The description part does not belong to a Measure, and should be moved to the Background Information Section that a Results-based standard template has made provision for. l. Measure M3: the latter part of M3 is not presented in a manner to require the evidence to demonstrate compliance. We suggest M3 be revised to: The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3, or evidence that the status had been restored within the first 15 minutes of such change. m. For all Measures, there are no examples of evidence provided. It will be appropriate if after each of the "evidence", additional wording "such as log, recording, or other documents" so as to be consistent with the way measures are presented in other standards. n. Evidence Retention: It will be appropriate to reference the Measure Number for the GO's and the GOP's data retention requirements.
No
NERC's Reliability Issue Steering Committee (RISC) is charged to address emerging reliability issues and recommend preferred approaches to manage such issues. Whether or not the TOP/GOP voltage coordination issue should rise up to a risk level that warrants special attention by the industry, and whether the appropriate way to address this issue in a standard project will be best evaluated and determined by the RISC. We suggest that the SDT nominate this issue to the RISC for its deliberation.
Individual
Clay Young
SCE&G
Yes
1. There is a general concern with this proposed standard that it will create further administrative burden for the TOP/RC as well as the back office staff. Additionally, the opportunity exists that the number of calls between the GOP and TOP will increase without materially enhancing BES reliability. Further, how would these standards be used to evaluate the compliance of a unit which has their AVR taken off auto for testing? 2. VAR-001-4 Comments: R1.1.2. Each Transmission Operator shall Delete: "provide a copy of these Comment Form-2013-04 VAR-001-4/VAR-002-3 July 2013 Page 2 of 5 https://www.nerc.net/nercsurvey/Survey.aspx?s=c645f86a592f47c9ae532b7c11d92eb1&Re... 9/3/2013 documented policies or procedures to adjacent Transmission Operators" make plans available with a written request so entities requiring documents have access. R1.1.3. Each Transmission Operator shall Delete:"provide a copy of these documented policies or procedures to its Reliability Coordinator." make plans available with a written request so entities requiring documents have access. R2. Each Transmission Operator and Reliability Coordinator shall perform assessments on their respective areas in order to ensure sufficient reactive resources are available Delete: "for scheduling" to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1. R2.2.2. As a result of the assessments, each Transmission Operator shall ensure that sufficient reactive resources Delete: " have been scheduled" Add: "are available" to meet acceptable day-ahead voltage limits identified in Requirement R1. Sufficient reactive resources may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; and controllable load. R5. The Transmission Operator shall know the status of Delete:"all transmission" Add: " BES" Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. Request that the SDT review R5 to ensure that it is not a duplicative of a TOP standard. M5. The Transmission Operator shall have evidence to show Reactive Power resources are being monitored. Evidence may include, but is not limited to screen shots of EMS/SCADA data, alarms, and phone logs. In the event the monitoring system does not work, each Transmission Operator should have a protocol in place to show these resources are being monitored. Request the SDT to add further clarification for AVR and PSS.
Yes
See answer to question 1.
Yes

See answer to question 1.
Group
Santee Cooper
S. Tom Abrams
No
No
We agree with the SERC Generation Subcommittee comments.
Individual
Thomas Hanzlik
SCE&G
Yes
1. There is a general concern with this proposed standard that it will create further administrative burden for the TOP/RC as well as the back office staff. Additionally, the opportunity exists that the number of calls between the GOP and TOP will increase without materially enhancing BES reliability. Further, how would these standards be used to evaluate the compliance of a unit which has their AVR taken off auto for testing?
Yes
R1.1.2. Each Transmission Operator shall Delete: “provide a copy of these Comment Form-2013-04 VAR-001-4/VAR-002-3 July 2013 Page 2 of 5 https://www.nerc.net/nercsurvey/Survey.aspx?s=c645f86a592f47c9ae532b7c11d92eb1&Re... 9/3/2013 documented policies or procedures to adjacent Transmission Operators” make plans available with a written request so entities requiring documents have access. R1.1.3. Each Transmission Operator shall Delete:“provide a copy of these documented policies or procedures to its Reliability Coordinator.” make plans available with a written request so entities requiring documents have access. R2. Each Transmission Operator and Reliability Coordinator shall perform assessments on their respective areas in order to ensure sufficient reactive resources are available Delete: “for scheduling” to maintain voltage stability under normal and contingency conditions in order to provide the voltage levels as defined in Requirement R1. R2.2.2. As a result of the assessments, each Transmission Operator shall ensure that sufficient reactive resources Delete: “ have been scheduled” Add: “are available” to meet acceptable day-ahead voltage limits identified in Requirement R1. Sufficient reactive resources may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; and controllable load. R5. The Transmission Operator shall know the status of Delete:”all transmission” Add: “ BES” Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. Request that the SDT review R5 to ensure that it is not a duplicative of a TOP standard. M5. The Transmission Operator shall have evidence to show Reactive Power resources are being monitored. Evidence may include, but is not limited to screen shots of EMS/SCADA data, alarms, and phone logs. In the event the monitoring system does not work, each Transmission Operator should have a protocol in place to show these resources are being monitored. Request the SDT to add further clarification for AVR and PSS.
No
Individual
Laurie Williams
PNM Resources, Inc.

No
Yes
PNM disagrees and cast a negative ballot vote due exclusively with the implementation timeframe of one calendar quater. One calendar quater does not appear to be enough time to prepare a documented policy or procedure for assessments that is required of Transmission Operators nor does it allow sufficient time for the newly applicable RC function to prepare its compliance documentation as well as ensure processes/procedures are established and working well prior to the effective date. Finally, Transmission Operators t which were not previously providing voltage/reactive tolerance bands will need additional time to establish this exchange with Generator Operators. PNMR suggests a minimum of 2 calendar quarters for implementation to ensure registered entities are not forced to self report non-compliance due to the extraordinarily short implementation schedule. PNMR has no issues with the wording in the standards and is otherwise in favor of the new proposed standards.
No
None.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
Yes
For requirement R1, Austin Energy proposes that the standard include generator “testing mode” in the exemption criteria. Austin Energy proposes the following for R1-first bullet item: ”That the generator is being operated in start-up, shutdown or testing mode pursuant to a Real-Time communication or a ………”
Yes
Austin Energy believes Requirement 2.1 is not focusing on the most useful metric for Transmission voltage stability. In the ERCOT Region, the Transmission Operators (Local Control Centers) monitor voltage on their Facilities and, when necessary, control the voltage by operating or directing the operation of reactive devices including reactive generation scheduling. The Generator Operator responds to requests from the Local Control Center for voltage support and notifies the Local Control Center if it is unable to provide voltage support. Asking the GOP to monitor voltage at the GSU and notify the TOP of certain deviations is somewhat redundant and not useful because the Local Control Center already monitors voltage at the system level and directs the Generator to alter MVAR output. Typically, in the ERCOT Region, the Generator and Generator Operator have no visibility into the larger system voltage and operate in a responsive mode. Generator equipment settings (Tap Settings & MVAR Settings) are set to meet the assigned voltage schedule under normal operating conditions and are adjusted only when a request for voltage support is received. Therefore, Austin Energy recommends altering the requirement to read “If the GOP is unable to meet the reactive support requested by the TOP due to equipment limitations it shall notify the Transmission Operator”, as already required in R2.3.
These comments apply to the VSLs (you did not provide an opportunity to do so elsewhere in this comment form): It looks like the VSLs for R2 show up for R4 and vice versa. R4 is merely a requirement to provide data, yet the VSLs address failing to maintain voltage schedules. On the other hand, the VSL for R2 has only a "severe" entry and penalizes the Registered Entity only if it fails to perform ANY sub-requirement (there are three). That doesn't seem correct. Finally, the VSL for R5 applies only if the Registered Entity does not perform BOTH requirements. That also appears incorrect.
Group
SPP Standards Review Group
Robert Rhodes

No
Yes
VAR-001-4 Replace ‘real time’ with ‘Real-time’ in the Purpose and throughout the standard. It is a NERC defined term. R1 requires the TOP to have policies and procedures that establish, monitor and control voltage levels and Reactive Power flows in the Operations timeframe. Is the requirement stating that the Transmission Operator must develop the voltage and reactive schedules in Real-time? This function is typically performed behind the scenes by Transmission Planners or other support staff. We suggest that the wording be changed by deleting ‘establish’. Additionally, the white paper states that the Operations timeframe is from Real-time up to one year in the future. Real-time, according to NERC Time Horizons document, is within one hour or less while Operations Planning is from day-ahead to up and including seasonal. We suggest this be revised to state the Real-time Operations thru Operations Planning time horizons. R1.2 and R1.3 are redundant with TOP-004-2, R6 and do not need to be repeated in this standard. We recommend deleting these two sub-requirements. In M1 insert ‘and controlled’ in the 6th line after ‘monitored’ such that the sentence states ‘…is currently being monitored and controlled.’ Also inisert ‘adjacent’ in front of Transmission Operator and add an ‘s’ to Operator in the next to last line. R2 requires voltage stablility assessments to be conducted by the TOP but no direction is given on how often these assessments must be performed. While we’re not asking the drafting team to place specific time limits on when assessments must be performed we would like to know what conditions would drive the need for performing a new voltage assessment. This should then be incorporated into the requirement. Also, are references to online assessments referring to Real-time snapshots for input into steady state voltage analysis or are they referring to dynamic voltage stability assessments? Given that it is stated in the Rationale Box for R2 that online assessments are not being specifically required in this standard, what kind of assurances does a TOP have that an audit team won’t expect the TOP to have such functionality available on the control room floor? The word ‘switching’ is left by itself in the listing of resources in M2. We’re not real sure what it refers to but would suggest that we delete capacitor banks and switching and replace it with transmission line and reactive resource switching. This recognizes that switching out a transmission line or a reactor bank serves the same purpose as switching in a capacitor bank. Also, delete the 2nd ‘provide’ in the next to last line of M2. R3 exempts GOPs from R4 but GOPs are not required to do anything in R4. The exemption should apply to VAR-002-3, R2. This is stated in the white paper on Page 8 in the first line under Requirement 3. In the 4th line of M3 ‘maybe’ should be ‘may be’. R4 requires the TOP to direct the GOP to follow the voltage schedule the TOP provided to the GOP. R2 of VAR-002-3 requires the GOP to maintain its assigned voltage schedule and the TOP does not need to direct the GOP to follow it also. This is redundant and should be removed. For consistency with the Measure, delete last sentence of M3. We recommend retiring R6 because it is simply a mechanism for adhering to the requirements in R4. R4 is more of a results-based requirement – follow the provided schedule. R6 is providing one option to assist in following R4. It should be deleted. The VSLs for R2 do not match the requirement. In fact, they add requirements which are not included in the standard. We recommend deleting the Moderate VSL for R2 and revising the Severe VSL to read The Transmission Operator does not perform assessments of their area. Unless the VSLs for R4 are spread out among all categories; did not provide to one GOP for Low, two GOPs for Moderate, three GOPs for High and four or more GOPs for Severe, we would suggest simply deleting the existing High VSL, leaving only the Severe VSL. The VRF shown in R5 does not match the VRF in the VSL table. One is Medium and the other is Lower. Which is it? The justification for the inclusion of power system stabiliizers in R5 is weak to say the least. Why does this equipment need to be highlighted and other equipment, such as capacitor banks and reactors, not? TOP-006-3 R1 requires the TOP to know the status of all generation and transmission resources within its area. R2 goes on to specifically include static and rotating reactive resources. It would appear that R5 is then duplicative with these requirements and therefore could be retired. If AVRs and PSSs need to be highlighted, they should be highlighted in TOP-006 and not in this standard. VAR-002-3 We have a concern that the use of Generator Operator in this standard appears as an attempt to change the definition of GOP to the operator inside the plant control room. Some of the functionality referred to in the standard specifically points to the plant personnel rather than the NERC defined Generator Operator. For example, controlling the AVR. This is something that a plant operator would do not the Generator Operator consolidating several plants at some remote location. This would be similar to field support personnel in a transmission setting. We suggest changing the responsibility to plant

personnel. We recommend replacing ‘directed’ with ’provided‘ in R2 and R2.2. The way the timing logic is written in R2.1 if a GOP is outside the tolerance band for longer than 15 minutes and the GOP has the capability to return to control, the GOP does not have to notify its TOP. Either the ‘and’ needs to be changed to an ‘or’ or the sub-requirement needs to be totally rewritten. Delete ‘associated’ when referring to TOPs in R3, M3 and R5. We recommend moving the VSLs from R4 to R2 with the following changes: LOW – When unable to maintain voltage or reactive power schedule the Generator Operator notified its TOP in more than 30 minutes but within 45 minutes. MODERATE – When unable to maintain voltage or reactive power schedule the Generator Operator notified its TOP in more than 45 minutes but within 60 minutes. HIGH – When unable to maintain voltage or reactive power schedule the Generator Operator notified its TOP in more than 60 minutes but within 75 minutes. SEVERE – When unable to maintain voltage or reactive power schedule the Generator Operator notified its TOP in more than 75 minutes or did not notify its TOP at all. We recommend changing the Severe VSL in R3 to: The responsible entity did not notify its TOP of a status or capability change as specified in R3. The provided VSLs for R4 probably belong to R2 and could be used there if the drafting team chooses to dispurse the severity of the violations across the VSL spectrum. We recommend the following for the VSLs for R4. LOW – The Generator Operator provided the data requested in R4 in more than 30 days but within 45 days. MODERATE – The Generator Operator provided the data requested in R4 in more than 45 days but within 60 days. HIGH – The Generator Operator provided the data requested in R4 in more than 60 days but within 75 days. SEVERE – The Generator Operator provided the data requested in R4 in more than 75 days or the Generator Operator did not provide the data at all. We recommend changing the Severe VSL in R5 to: The responsible entity did not perform the specified tap change and failed to provide the technical justification to its TOP as to why it did not comply with the request as required in R5.
Yes
Please see our comment in Question 2.
The information provided is not sufficient to make this determination. Additional, specific information regarding precisely what the issues are is needed.
Group
Bonneville Power Administration
Jamison Dye
No
Yes
BPA considers the impact of large renewable generation projects (asynchronous machines) in our interconnection requirements and recognizes the ability of these machines or their auxiliary devices to support voltage. BPA recommends the drafting team address renewable resource voltage control in VAR-002-3. BPA believes that VAR-001-4, Requirements R1.1 and R2 are redundant as they appear to overlap with existing Mandatory standards. FAC-011-2, Requirements R1, R2 and R3 establish that the RC Methodology includes process and pre/post contingency performance, including margins. FAC-014-2, R2 instruct the TOP to establish SOL’s in accordance with the RC Methodology. Because of this, BPA believes that VAR-001-4, R1.1 is already established in these FAC standard requirements. Additionally TOP-002, R11 requires the TOP to perform seasonal, next day and current day studies to determine SOL’s. Because of this, BPA believes that VAR-001-4, R2 appears to be redundant. BPA recommends the elimination of R1.1 and R2 of VAR-001-4 to remove this redundancy.
No
Group
PacifiCorp
Kelly Cumiskey
No

Yes
PacifiCorp would like to point out that there is no uniform method with which voltage schedules are established in R1 of VAR-001-4. If there isn't anything specific that a TOP is expected to look at or address when drafting the procedures or policies for establishing voltage schedules, it is not clear to PacifiCorp how the policies and procedures will be measured. Moreover, if the policies and procedures only include a TOP's own criteria for the studies used to establish voltage schedules, how does requiring a documented policy and procedure in the reliability standard (referenced on page 7 of the NERC White Paper) "remove the opportunity for auditors or other parties to scrutinize a TOP's own system studies"? Additionally, PacifiCorp would like more clarity with respect to how real-time reactive deficiencies are expected to be identified in R2 of VAR-001-4. The rationale for R2 states that the informal development team believed the requirement should not require a utility to purchase new online simulation tools but in the absence of such tools, it is not clear to PacifiCorp how real-time reactive deficiencies can be captured.
No
Individual
Ryan Walter
Tri-State Generation and Transmission Association, Inc.
No
Yes
In the draft of VAR-001-4 R2 the use of the word 'schedule' when referring to all reactive resources is unclear. This is in conjunction with the Compliance response to question 2 part 2, "…provide the documentation for the day ahead scheduling in addition to documentation supporting that it was scheduled…" found in the NERC document Draft Reliability Standard Compliance Guidance for VAR-001 and VAR-002 dated July 8, 2013. Is it the ad hoc group's intent to have a schedule for all reactive resources including capacitors, reactors, Static var Compensators and generators? Is the schedule meant to be similar to that of a generator (i.e. Insert capacitors at 1.0pu and remove at 1.05) or on a time base? Is schedule just supposed to take into account availability of all reactive resources? For VAR-001-4 R4 Tri-State Generation and Transmission Association, Inc. (TSGT) believes it would be beneficial to include a feedback loop from the GOP to the TOP when there are generator capability concerns with regards to the TOP's supplied voltage schedule. Also TSGT believes the statement "(at either the high or low side of the Generator Step-Up transformer at the TOP's discretion)" currently in VAR-001-4 R4 to should be changed to "(at an agreed upon metering point to which the GOP has direct access)." For VAR-001-4 R6 why did the ad hoc group not change the consultation requirement from GO to GOP? Tri-State believes that this information would better serve the GOP function particularly at Co-Owned facilities. This change would not have a negative effect on the reliability of the BES would reduce duplicative notification to be administered by the TOP. TSGT suggests the ad hoc group add the statement "Notification to the TOP is not required if the GOP can return to schedule" to the end of VAR-002-3 R2.1 to provide further clarification when notification is needed. For VAR-002-3 R5 TSGT believes the TOP should consult with the GOP rather than the GO to better align requirement R5 with its subrequirement R5.1.
No
TSGT does think a feedback loop would be beneficial for VAR-001-4 R4 as noted in our comment to question 2.
Individual
Denise Yaffe
Southern California Edison
No

No
No
SCE commends the drafting team on the work that it has done to address the FERC directives in Order 693 to modify VAR-001. The draft standard is an excellent baseline/ starting point to accomplish this endeavor the draft VAR-001-4 standard, currently out for comment and balloting, still needs additional clarity and refinement before it can be moved forward and go into effect. An example of the need for clarity can be found in the Requirement 1.1, and the use of the term "system assessment". The drafting team should better describe this term as it is somewhat ambiguous in nature.
Group
NAGF Standards Review Team
Patrick Brown
Yes
VAR-001: 1. The rationale statement for R1 of VAR-001 says that it, “will allow each Transmission Operator (TOP) to establish its own policies and procedures,” regarding voltage schedules and tolerance bands. This wording does nothing to prevent specifying an unreasonably-tight bandwidth (e.g. +/- 0.5%), as some parties are now doing. We suggest that R1.1 end as follows, “…voltage schedules along with associated tolerance bands of not less than 1.5% of the schedule voltage unless technically justified.” There may be some resistance to making the standard prescriptive, but it’s not a burdensome requirement, and it would be unfortunate to update the standard without addressing known abuses of the present version. 2. The statement, “Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band (at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion) at the interconnection point between the generator facility and the Transmission Owner's facilities,” in R4 of VAR-001 has a semantics glitch in that there is just one interconnect point. That is, mandating control at the interconnection eliminates any discretion in making the high vs. low-side selection. We suggest saying instead, “Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band, at the agreed upon metering point to which the GOP has access.” This will typically be either the transmission bus or the generator terminals. If the TOP specifies this as the TO’s “transmission bus”, the TO should be required to make the same voltage point used by the TOP available to the GOP to ensure both are seeing the exact same voltage. Additionally, there needs to be a feedback loop from the GOP to the TOP regarding the voltage schedule. This does not mean we want to spark a debate every time a schedule is provided, but simply add a step that allows a GOP to provide feedback regarding the feasability of the schedule. A recommended R4.2: R4.2 The Generator Operator shall review the voltage or Reactive Power schedule and tolerance band provided by the Transmission Operator and inform the Transmission Operator of any conditions that would prevent the Generator Operator from complying with the schedule or tolerance band, along with the technical basis for that determination. The question that then comes up is, what does the TOP do if the GOP cannot comply with the schedule as presented? Recommended R4.3: R4.3 If the Generator Operator is unable to comply with the voltage or Reactive Power schedule or tolerance band as provided by the Transmission Operator, the Transmission Operator shall (a) modify the voltage schedule within the parameters established in the documented policies and procedures established in R1, taking into account the Generator Operator’s limitations, or (b) exempt the Generator Operator from following the voltage schedule or tolerance band using the criteria established in R3. 3. We’d like to see R6 of VAR-001 changed to, “After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes that is mutually agreed, and technical justification for these changes.” That is, the change should normally wait until it can be rolled into a scheduled downtime event. We sometimes get people studying things for numerous months, then when finally reaching a decision wanting to know why we can’t make the change in the next day or two. VAR-002: 1. We suggest changing, “The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to

operate a generator in the automatic voltage control mode as specified in Requirement 1," in M1 of VAR-002 to a more semantically neutral, "The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it did not operate a generator in the automatic voltage control mode." 2. The SRT recommends the following changes to R2, for clarity; R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule3 (within each unit's ratings or capabilities4) as directed by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] 3. We suggest corresponding changes to R2.1. Note that the time frames are left blank in our recommendation, as there is still much discussion within the industry as to what an approporitate timeframe would be; If the system bus voltage drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator within __ minutes when both of the following conditions are met: 1) the GOP has been operating outside of the prescribed voltage or Reactive Power schedule tolerance band5 for __ minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule. Notification to the TOP is not required if the GOP can return to schedule. 4. In line with the recommended changes above, we suggest changing M2 to; Generator Operators shall operate the generators to help minimize excursions outside the established tolerance bands for the agreed-upon metering point. It is recognized that excursions may occur outside of the tolerance bands during unit start-up and shut-down, during MW and MVAR loading at a transmission bus where multiple units are connected, during time of relatively sudden transmission system loading changes, during system events and when grid conditions are beyond the capability of a generator to correct. Therefore, when the system bus voltage is out of the tolerance band, the Generator Operator will not be held in non-compliance with this requirement if the sub-requirements 2.1, 2.2, and 2.3 are met. In order to identify when a unit is deviating from its schedule, GOPs will monitor voltage at the agreed upon metering point to which the GOP has access. Therefore, GOPs have the option to operate on a voltage schedule on either the high-side or convert the high-side schedule to a low-side schedule at the GOP's discretion. For units that monitor on the low-side/terminal voltage, Generator Operators shall provide evidence of the method of conversion from the high-side schedule to low-side monitoring. GOP shall have evidence to show compliance with requirement R2 by providing 1) Communications with the TOP when the Generator Operator was operating outside of the prescribed voltage or Reactive Power schedule tolerance band for __ minutes AND Generator Operator was unable to return the generator to operation within its voltage or Reactive Power schedule tolerance bands; 2) Generator Operator implemented an alternative method to control reactive output when the AVR was out-of-service or unavailable; 3) compliance with directive to modify voltage or a notification that the directive could not be met. Evidence may include, but is not limited to Generator Operator logs, SCADA data, phone logs, and any other alarming notifications that would alert the Transmission Operator that both conditions were met. Timing for Requirement R2.1 can be crucial during system events, and Generator Operators are expected to begin timing when notified of an event by the TOP as soon as the unit is operating outside of the tolerance band. Further, voltage documentation during a system event may be requested by an auditor to show measures were taken to bring the unit back into schedule. 5. To harmonize Footnote 4 with our recommended language for R2, we suggest Footnote 4 be revised to state; For the operations horizon, the GOP may choose a test-based or real-time method of establishing a unit's reactive power capability. The test-based capability is that determined for compliance with MOD-025. Parameters typically monitored for determining real-time capability may include 1) generator loading (MW, MVAR, amps), temperatures, and terminal voltage; 2) GSU loading and temperatures; 3) auxiliary bus voltages; 4) plant auxiliary equipment loadings, temperatures, and voltages; 5) Generator and GSU Volts/Hz limits; 6) excitation system and/or AVR limits. 6. If R2.1 sticks, we would like to see M2 clearly state that "if the GOP can return to schedule, he does not have to notify the TOP." 7. For the new footnote 6 referenced above; The TOP is to establish an official-for-compliance bus and phase voltage point for monitoring compliance of generators controlling to the high-side voltage. An excursion begins for compliance purposes when the measured voltage exceeds the bandwidth boundary by a recognizable amount (0.5%). Multiple notifications to the TOP need not be made when the system voltage wanders back and forth across the bandwidth boundary. The system voltage must be back within the boundary for one hour before the next excursion counts as a separate event. 8. VAR-002, R2.2 should read, "When a generator's automatic voltage regulator is out-of-service, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator, unless the TOP grants an exemption." The purpose of this change is to reference the process established in R3 of VAR-001. 9. VAR-002, R4 should be revised to state; "For

generator step-up and auxiliary transformers with nominal primary voltages equal to the generator terminal voltage:" This is to clarify that R4 is N/A to startup transformers and other station auxiliary transformers connected to a HV bus at a plant. 10. VAR-002, R5 should read, "after consultation with the Transmission Operator and agreement on schedule regarding necessary step-up transformer tap changes…'" for the reason stated under comment 3 above. Regarding the Technical Whitepaper; 1. The statement on p.7 that, "the more VARs produced at a generating facility, the fewer MWs produced," would be true only if operating to the generator OEM D-curve limit, and many generation units are instead typically limited by generator voltage limits due to variations in aux bus voltages. Under the latter situation raising and lower reactive power export or import does not affect the MW capability. 2. The statement on p.7 that "the informal development group did not want to place numerical requirements on what the proper operational limits should be for the continent," fails to consider that there are present-day abuses of the system that should be addressed in the VAR-001 update. Self-policing isn't working, hence our comment #1 above. 3. Ref. "unit drifts out of schedule," on p.9 it is the system that is drifting, not generation units. 4. The statement on p.10, "This industry divide is not addressed in the pro forma standard presented today," appears to account for some of the ambiguity discussed in the NAGF's comments. We believe that requirements need to be unambiguous, however, and there must also exist explicit and achievable means of achieving compliance. 5. While there is a sentence in the measure that states it is clearly the generator's discretion as to whether they monitor (presumably control) low side or high side to demonstrate compliance, we believe that there is still a substantial amount of language in the Standard and the Whitepaper that would tend to cloud that by implying that a generator should monitor high side for compliance if you have high side equipment installed; in other words, the monitoring/control point is based on current installed equipment. 6. Additionally, the Whitepaper does nothing to shed light on whether generators should make manual moves to reactive output (by changing the AVR low side set-point) without explicit direction form the TOP which leaves the compliance application open for interpretation.
Yes
1. In order 693 Page 488 the FERC "directive" for VAR-002 stated, "Dynegy has suggested an improvement to Reliability Standard VAR-002-1, and NERC should consider this in its Reliability Standards development process." Dynegy's concern stated, "VAR-002-1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an 'incident' of non compliance." Dynegy offered two alternatives to address their concern: "…[1] either more detail should be added to the Reliability Standard to cure this omission, Or [2] the Reliability Standard should require the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator." Their reasoning: "… this approach will eliminate the potential for undue discrimination and the imposition of overly conservative or excessively wide time frame requirements, both of which could be detrimental to grid reliability." Note that voltage tolerance band is not mentioned. 2. Going from NERC "should consider" Dynegy's suggested improvements to a very prescriptive time requirement (embedded in a VSL) in the current version of VAR-002 was a big step from the generation perspective. Also, it appears that Dynegy's second alternative was ignored during this step. 3. In the 2013 FERC Order approving VAR-002-2b (current version which became effective on July 1, 2013): PPL presented valid arguments against the "zero tolerance" time frame deviation introduced in the VSLs from the generator operator perspective (see Paragraphs 15 and 16). Both NERC and FERC rejected PPL's arguments. Paragraph 17 states, "NERC argues that the proposed modification would allow for a deviation in system voltage for up to 30 minutes to allow for time to correct an excursion and that such deviations from a voltage and reactive schedule is inappropriate because a deviation even up to a few minutes can negatively impact reliability." Paragraph 18 goes on to say, "NERC maintains that significant voltage deviations for extended periods of time may lead to voltage collapse and can increase the potential for a wide-area impact to the reliability of the Bulk-Power System, and as such PPL Companies' proposed modification to the VSL language should be rejected." The context of the NERC and FERC discussions and agreement on the rigid time requirement apparently assumes all TOP's voltage schedule tolerance bands are reasonable and "reliability based". Also, there seems to be an absence of discussion on Dynegy's 2nd alternative for the "the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator." However, the Pro Forma VAR R1 will require each TOP to have documented policies or procedures used to "establish, monitor, and controls voltage levels and Reactive Power flows within limits as defined below: R1.1 These documented policies or procedures shall include criteria used in system

assessments. The criteria for the assessments shall include established steady-state limits, voltage stability limits and associated operating margins, and voltage schedules along with associated tolerance bands." Thus, a fair question on the Pro Forma standards follows: If VAR-001 R1.1 is met, can GOPs conclude that each TOP's tolerance bands have a documented technical basis? If not, what mechanism will allow GOPs to question extremely narrow voltage or reactive power schedule tolerance bands that make compliance with VAR-002 R2.1 difficult or impossible? Note the Background discussions in the White Paper (see Pages 7 – 10). The discussion for VAR-001 R4 states, "The informal development group is cognizant of the fact that the nature of reactive power on the network varies depending on local conditions. Thus, the group focused on the process that the requirements would detail, not the proper numbers a TOP should enforce in the standard. For VAR-001, the group would not put operational limits on how a TOP should manage voltage stability for its regions; more specifically, the informal development group did not want to place numerical requirements on what the proper operational limits should be for the continent. Operating margins vary due to specific system characteristics as well as the operating conditions." This begs the question: Why was this same rationale not applied in addressing the time frame? 4. The published reasons for the changes to VAR-002 include 1) eliminating nuisance calls and mitigating compliance issues for generators (i.e. non-reliability gap reducing violations), and 2) addressing the FERC directive to NERC to "consider a timeframe" for allowing a generator to be out of schedule before having to make a notification to its TOP. It could be argued that imposition of a very prescriptive time frame alone does not fully address the FERC "directive" language and the first Pro Forma objective of reducing nuisance calls (GOP to TOP), especially if the voltage tolerance bands are extremely tight or do not have a technical basis.
Individual
Texas Reliability Entity
Texas Reliability Entity
Yes
VAR-001----R1 is too vague and general and nature. It does not establish a time period for compliance, and it does not provide sufficient criteria to allow an entity or an auditor to determine whether the "policies and procedures" are effective and adequate to satisfy the standard.
Yes
***VAR-001---- (1) R2.2 refers to "day-ahead voltage limits identified in Requirement R1," but R1 does not have a timeframe associated with it, and it does not expressly require identification of "day-ahead voltage limits." (2) The Measures include many details that appear to be intended to flesh out the requirements, not just to explain what will be expected to demonstrate compliance with the requirements. For example, most of M3 deals with "temporary exemptions," but there is no mention of "temporary exemptions" in R3. (3) In R4, is the specified voltage and tolerance band at the GSU or at the interconnection point (which in many cases is not the GSU)? In a world with long lead lines, setting a definite unique location for a voltage point and associated tolerance is required. ***VAR-002---- (1) Actions necessary to maintain a voltage or Reactive Power schedule are needed to prevent drift. As written the GOP would only have to be within its voltage or Reactive Power schedule for 2 minutes of a given hour and never notify its TOP. Is that what is intended? (2) Measure M2 contains an enormous amount of information that appears intended to modify the requirement – that is not the purpose of a measure. The requirement should be written to capture all of the elements of and exceptions to the requirement. (3) R3 ignores the requirement for the TOP in VAR-001-4 to know the status of "all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system" as defined in VAR-001-4 R5. (4) In R5, there is a disconnect between actions by a GO in R5 and actions by a GOP in R5.1. (5) The VSL for R2 should be reconsidered. This does not appear to be a binary requirement, as multiple levels of non-compliance could be identified. Also, does the VSL require ALL sub-requirements to not be met before a non-compliance occurs—the language used is ambiguous. (6) The VSL for R4 does not correspond to the language of R4 (R4-data within 30 days of a request---VSL talks about timeframes of not meeting a schedule). (7) The VSL for R5 fails to recognize the role of a GO as stated in the requirement.
Yes
As written the GOP would only have to be within its voltage or Reactive Power schedule for 2 minutes

of a given hour and never notify its TOP. Is that what is intended?
Group
Western Electricity Coordinating Council
Steve Rueckert
Yes
WECC notes that Requirement R3.2 has been deleted from the proposed standard. The proposed R3 in VAR-002-3 still requires the GOP to notify its associated TOP of a status or capbility change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer (old R3.1) but the requirement for the GOP to notify its associated TOP of a status or capbility change on any other Reactive Power resource under the GOP's control (old R3.2) is no longer included in the proposed VAR-002-3. What is the purpose of removing this requirement?
No
Individual
Richard Vine
California Independent System Operator
Agree
IRC/Standards Review Committee
Individual
David Wang
SDG&E
San Diego Gas and Electric
No
Yes
R.1. This requirement is very unclear and the objective is undefined for the Transmission Operator in establishing the criteria for the system assessments that are to be included in the required policy. TOPs establish their operating limits (SOLs and IROLs) based on NERC and WECC RC (in the west) criteria. Would this established criteria (in the west) be the intended ‘criteria’ that should be used in a TOP’s system assessment in the WECC region for this requirement or are there other minimum criteria that are expected to be included to meet compliance with this requirement? When establishing these operating limits, voltage and reactive requirements are captured when the WECC RC criteria is applied as required as part of the compliance with FAC-014-2 R2 for TOP entities in the WECC region. Does the establishment of this requirement create an unintended duplication of the reliability standards? These studies follow a specific methodology and criteria established and used, but requirement 1.1 refers to a criteria that is not entirely clear on what the TOP should be using.
No
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
No

Yes
On VAR-001 and VAR-002 regarding voltage schedule and compliance: The published reasons for the changes to these standards are 1) to eliminate nuisance calls and non-reliability gap reducing violations, and 2) to address the FERC directive to NERC to "consider a timeframe" for allowing a generator to be out of schedule before having to make a notification to its TOP. The changes to the standards do not fully address the first objective of reducing nuisance calls (GOP to TOP) regarding being off schedule. In addition, we have considered the idea of notification timeframes and do not suggest including such GOP notifications in the revised VAR-002. Currently, GOPs are required to maintain generator voltage or Reactive Power Schedules as directed by the TOP. If the GOP experiences problems maintaining voltage schedules, the TOPs, if warranted, will notify the GOP to either maintain or modify their voltage schedule as needed to maintain reliability of the TOP area. This existing construct has proved to work well and a new notification requirement is unnecessary. VAR-001-4 R1 Comments: Regarding R1 Part 1.1, the language addressing the specification for the criteria for the assessments needs refining. Regarding the verbiage specifying the inclusion of “estabilished steady-state limits”, while one would assume that means voltage level steady state limits, this needs to be clarified. Otherwise, it could be mis-interpreted to include steady state Mvar flows or other power system quantities. Also, the inclusion of voltage stability limits and operating margins is not applicable to all TOP footprints. Voltage stability limits manifests as the potential limiting phenomena in systems with high transfers or dense loads served over high nominal voltage kV transmission lines. Transmissions systems that are predominately load serving by local generation over lower nominal kV transmission lines are often shown, through off-line studies, to be limited by thermal and/or voltage level limits far in advance of voltage stability limits. Given that voltage stability analysis is not trival, this verbiage is burdensome and would require subject matter expertise that is not widely available for no reliability gain. Would suggest chaning the verbiage to “…..for systems where voltage stability limits are potentially the limiting phenomiena, the criteria for the assessment should also inlcude voltage stability limits and associated …….” Finally, need to include that voltage stability limits can be identified in off-line studies. VAR-001-4 R2 Comments: Modify R2 from…..”….are available for scheduling to maintain voltage stability under normal and contingency conditions conditions in order to provide the voltage levels as defined in Requirement R1” to ….”….are available to provide the voltage levels as defined in Requirement R1”. If the voltage limits found in R1 are honored, inheritently, any voltage stability limit will also be honored. Note for voltage stability limits associated with high transfer over EHV corridors, the corresponding pre-contingency voltage level limit may be near levels which are normally considered acceptable. In addition, VAR-001-4 R2 is redundant with several existing and future enforceable standards: TOP Requirements TOP-002 R10 and R11 & TOP-003 R1 and 2: The proposed VAR-001-4 R2 is redundant with the existing TOP-002 Requirements 10 and 11 that require operational assessments so that TOPs can plan to meet all SOLs and IROLs which include voltage limits. TOP-002 R10 and R11 will be replaced with TOP-003 Requirements 1 and 2 when the “Real Time Operations” project is approved by FERC. TOP-003 R1 and R2 require operational assessments to be able to operate within SOLs and IROLs as well. TOP-004-2 R6: VAR-001-4 R2 is also redundant with TOP-004-2 R6. The Real Time Operations SDT recognized that TOP-004-2 R6 was covered by TOP-001-2 which requires TOPs to operate within SOLs and IROLs. TOPs must perform assessments to be able to operate within such limits; therefore, the proposed VAR-001-4 R2 is redundant with TOP-004-2 R6 and TOP-001-2 when approved by FERC. RC Requirements FAC-011-2: The purpose of FAC-011-2 states, “To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” Since this requires documented methodology for SOLs, which includes voltage and stability limits, VAR-001-4 R2 is redundant with FAC-011-2. FAC-014-2: The purpose of FAC-014-2 states, “To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.” Since this standard requires establishment of SOLs and IROLs, which include voltage and stability limits, VAR-001-4 R2 is redundant with FAC-014-2. IRO-008-1 R1: VAR-001-4 R2 is also redundant with IRO-008-1 R1 that requires RCs to perform assessments to ensure they do not exceed IROLs. IRO-005-3a : The proposed VAR-001-4 R2 is redundant with the existing IRO-005-3a R1 and its sub-requiremetns. It has been proposed to retire IRO-005-3a R1 and its sub-requirements with the SDTs rationale of “monitoring capability can be objectively measured and is essential to real-time operations – however real-time monitoring is a supporting activity and is only one of several processes used to support operation within defined parameters. Monitoring capability should be assessed during certification of an RC and not as a

requirement. " Given the IRO-005 SDT's rationale, the fact that the NERC BOT approved IRO-005-4, and the fact that assessments are already required in other existing Reliability Standards, VAR-001-4 R2 should be deleted. VAR-001-4 R4: The statement, "Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band (at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion) at the interconnection point between the generator facility and the Transmission Owner's facilities has a semantics glitch in that there is just one interconnect point. That is, mandating control at the interconnection eliminates any discretion in making the high vs. low-side selection. We suggest saying instead, "Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band, at the agreed upon metering point to which the GOP has access." This will typically be either the transmission bus or the generator terminals. If the TOP specifies this as the TO's "transmission bus", the TO should be required to make the same voltage point used by the TOP available to the GOP to ensure both are seeing the exact same voltage. VAR-001-4 R5 is redundant with the existing TOP-006-2 (R1 and R2), which states the following, and with the proposed TOP-003-2 that requires TOPs to specify and entities to provide data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. VAR-001-4 R5 is redundant with the existing TOP-006-2 R5 because it also requires TOPs to know the status of resources to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. The Real Time Operations SDT proposed to delete this requirement as it should be covered in the certification process for RCs, TOPs, and BAs. The SDT also noted that this requirement was covered by over enforceable reliability standards (BAL-005, TOP-001, and IRO-008); thus the proposed VAR-001-4 R5 is redundant and should be deleted. In addition, the reactive resources are the generator and not the ancillary resources such as AVR and PSS. VAR-001 R6: Generators should be allowed to make these changes during a scheduled unit downtime as long as the time is within a reasonable period of time. We suggest the time be within 12 months and propose the following rewording fo this requirement: "After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes that is mutually agreed and no longer than 12 months, and technical justification for these changes." On VAR-002, R2: We recommend eliminating "Facility Ratings" in R2 and in the footnote of VAR-002 R2 footnote 4. Use of the NERC-defined term "Facility Ratings" presents a problem, because only occasionally do equipment ratings define the amount of reactive power that a generating unit can import or export. We suggest using the term "unit capabilities" in lieu of the term "Facility Ratings." The clarification in footnote 4, "When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings," only further confuses the issue. R2 should read, "Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule (within each unit's capabilities) as directed by the Transmission Operator." Footnote 4 should be moved to R2.2 and changed to "When a Generator is operating in manual control, reactive power capability may change based on stability considerations." On VAR-002, M2: a) remove "all" from "all attempts" and ; b) the documentation requirements listed in the measure are excessive and unreasonable and unduly burdensome. We recommend, alternatively (or in addition), a statement from the TOP is acceptable evidence of GOP compliance with R2 (the voltage support performance). On VAR-002, R4: This requirement should be revised to state; "For generator step-up and auxiliary transformers with nominal primary voltages equal to the generator terminal voltage:" This will clarify that R4 is N/A to startup transformers and other station auxiliary transformers connected to a HV bus at a plant. On VAR-002, R5 rational: We suggest modifying the rationale for R5, second sentence to read " If the tap setting is not properly set, then the VAR capability of a unit can be affected."
Yes
As previously stated in our response from Question #2: On VAR-001 and VAR-002 regarding voltage

schedule and compliance: The published reasons for the changes to these standards are 1) to eliminate nuisance calls and non-reliability gap reducing violations, and 2) to address the FERC directive to NERC to "consider a timeframe" for allowing a generator to be out of schedule before having to make a notification to its TOP. The changes to the standards do not fully address the first objective of reducing nuisance calls (GOP to TOP) regarding being off schedule. In addition, we have considered the idea of notification timeframes and do not suggest including such GOP notifications in the revised VAR-002. Currently, GOPs are required to maintain generator voltage or Reactive Power Schedules as directed by the TOP. If the GOP experiences problems maintaining voltage schedules, the TOPs, if warranted, will notify the GOP to either maintain or modify their voltage schedule as needed to maintain reliability of the TOP area. This existing construct has proved to work well and a new notification requirement is unnecessary.
We fully support the need for coordination between the TOP/GOP regarding the establishment of voltage schedules. We suggest that a joint tap coordination study be performed. VAR-002 R5 alludes to this need for coordination. This process should help identify any transmission system and generating unit limitations with respect to var limitations and voltage support.
Group
Western Area Power Administration
Lloyd A. Linke
Agree
US Bureau of Reclamation, except for requiring the drafting team from explaining why the WECC variation should be applied outside of WECC.
Individual
Alice Ireland
Xcel Energy
No
Yes
1) VAR-001-4, R1 -- Although a good results-based reliability requirement, there is significant overlap with FAC-014 with regards to establishing SOL and IROL. The FAC-14 requires TOP to establish steady-state and stability-limited SOLs in accordance to its RC SOL methodology. For example, in the WECC RC SOL methodology, the RC states criteria for steady-state limit, voltage stability, and operating margins (in accordance with FAC-011 requirements) which apply to each TOP. Having these criteria to be established again in VAR-001-4 creates an issue of “Double Jeopardy” with FAC-014 and FAC-011 since system assessment done for establishing SOLs is fundamentally no different than described in this R1. 2) VAR-001-4, R2 -- Although a good results-based reliability requirement, there is significant overlap with TOP-002 enforceable standard. The TOP-002 R11 that states “The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs”. Here the definition of SOLs already includes the steady state limits, voltage stability limit. So again, this creates a “Double Jeopardy” issue. It may be argued that TOP-002-3 has been approved by NERC BOD (but not by FERC yet) which may eliminate this issue. But even in the new TOP-002-3, R1 states “Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions” So even in this situation, the TOP already needs to have operating planning analysis... which is no different than performing assessment. 3) VAR-001-4, R2 addresses assessments for scheduling purposes while R2.1 mostly addresses real-time operation of devices. This seems inappropriate and we recommend moving R2.1 out to its own requirement. We believe that this requirement should include the RC as well as the TOP. The RC is required to do the assessment for scheduling in R2, but is not required to take any action to actually schedule the generation like the TOP is required to under R2.2. For example In the MISO region, the RC has more direct control over the generation dispatch than its members so I believe that they should also be subject to responsibility in R2.2. 4) VAR-002-3, Recommend firming up the language, such as “A Generator Operator shall notify its associated Transmission Operator…”. Also a timeframe needs to be applied to the second requirement to not

allow a GOP an infinite amount of time to return its voltage to the schedule. The M2 measure suggests that the reason the generator can't return to its schedule is because of a limiting factor. If that is the intent of the requirement, it should be stated in the requirement and not the measure. Part of the M2 measures seems to contradict statements made in the VAR-001-4 standard. M2 of VAR-002-3 states that the GOP has the "option to operate on a voltage schedule on either the high-side or convert the high-side schedule to a low-side schedule at the GOP's discretion" while R4 of VAR-001-4 states "Each Transmission Operator shall specify a voltage or Reactive Power schedule and tolerance band (at either the high side or low side of the Generator Step-Up transformer at the TOP's discretion)". This is confusing at best and contradictory at worse. Language in both standards should be cleaned up to clearly identify who has authority to determine where a voltage schedule is defined. 5) VAR-002-3, R2.1: Some vertically integrated utilities may have voltage monitoring systems managed by the TOP. In this case the notification would be done by the TOP to the GOP and the corrective actions jointly developed. Therefore, we suggest rewording R2.1 to something like this: [2.1. If a generating unit drifts out of the prescribed voltage or Reactive Power Schedule3 (within applicable Facility Ratings4) tolerance bands, the GOP and TOP shall have a process established to return the generator to the schedule or an acceptable alternative within 30 minutes.]
Individual
Roger Dufresne
Hydro-Québec Production
No
No
No
VAR-002-3 Regarding Measure M2, M2 presents the scenarios where a Generator Operator may not be able to meet a voltage schedule or comply with the TOP's directive, and how a GOP may manage the situations. The description part does not belong in a Measure, and should be moved to the Background Information Section that a Results-based standard template has made provision for. Regarding Measure M3, the latter part of M3 is not presented in a manner to require the evidence to demonstrate compliance. Suggest revising M3 to read: The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3, or evidence that the status had been restored within the first 15 minutes of such change. For all Measures, there are no examples of evidence provided. It would be appropriate if after each of the "evidence", additional wording "such as log, recording, or other documents" so as to be consistent with the way Measures are presented in other standards. Regarding Evidence Retention, it would be appropriate to reference the Measure Number for the GO's and the GOP's data retention requirements
Group
Electric Power Supply Association
Jack Cashin
Yes
EPSA believes that simultaneous processing of the SAR and the standard, as was done in this instance puts them at cross-purpose with one another. This risks a situation where if a SAR needs changes, stakeholder comments on standard will be based on a defective SAR that needs work and becomes an inefficient use of stakeholder resources. The SAR scope for proposed VAR-002-2 has not considered all the aspects that can ensure that the Standard will reach a steady state. Since its issuance in June of 2013, NERC and Stakeholders have recognized that the "Standards Independent Experts Review Project" provides a global assessment of Standards including VAR-002-2. The Independent Experts recommend that requirements that are part of VAR-002-2 are duplicative and covered under other

standards or covered by tariff requirements. To avoid duplication or conflating reliability and market issues the SAR scope would benefit from including the recommendations of the Independent Experts in the current VAR-002-2 project. This will avoid expending resources on the Independent Experts recommendations in the future.
No
No
Individual
Russ Schneider
Flathead Electric Cooperative
Yes
Overall, the implementaiton of this requirement seems paperwork heavy for Transmission Operators and seems to single out generators in the western interconnection.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

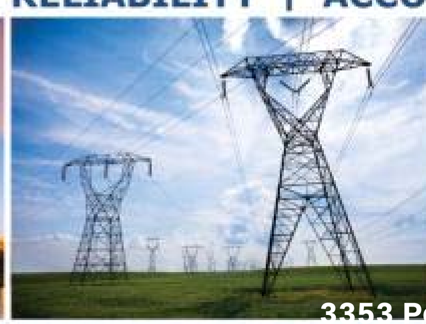
Consideration of Comments Summary

Project 2013-04 Voltage and Reactive Control

February 27, 2014

RELIABILITY | ACCOUNTABILITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Introduction

The Project 2013-04 standard drafting team (SDT) thanks all commenters who submitted comments on the draft VAR-002-3 standard. This standard was originally posted with VAR-001-4 for a 45-day public comment period from August 23, 2013 through September 3, 2013. Both proposed standards were revised and re-posted for a successive ballot from October 11, 2013 to November 26, 2013. VAR-001-4 received the necessary approval and went forward to a final ballot. However, VAR-002-3 only received 66.09% of the weighted segment vote. A total of 58 sets of comments were received during the second 45-day public comment period. This document will present a summary of the comments considers by the SDT after the most recent comment period for VAR-002-3.

All comments submitted may be reviewed in their original format on the standard's project page.[1]

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[2]

[1] The project page is available here: http://www.nerc.com/pa/Stand/Pages/Project2013-04VoltageReactiveControl.aspx.

[2] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Consideration of Comments

Purpose

The VAR SDT appreciates the comments from industry regarding the VAR-002-3 standard. All comments were reviewed carefully by the SDT and changes were made to the standard accordingly. While all comments were reviewed, the new Standards Process Manual (SPM) does not require responses to each individual comment when a successive ballot is needed. However, this document provides a summary of responses to comments. The following pages will provide a summary of the comments received and how the comments were addressed by the VAR SDT. If a specific comment was not addressed in the summary of comments, please contact the NERC Standards Developer or one of the SDT members to discuss.

Duplication

Several commenters suggested that VAR-002-3 duplicated requirements in the TOP and MOD standards, namely TOP-001, TOP-003, and MOD-032. The VAR SDT is very mindful that the TOP-001 and TOP-003 on file with FERC are currently being re-evaluated in a separate project, and the Commission recently recommended a full remand of those standards. There is also an on-going effort to review the TOP/IRO standards, and until those standards have been finalized and approved, the SDT could not rely on those standards as a premise to remove requirements from VAR-002-3. Further, the MOD-032 standard does not apply to Transmission Operators (the entity making the data requests that would precipitate VAR-002 compliance), and the operating horizons are different from the VAR standards. Therefore, the SDT could not remove requirements based on MOD-032 overlap.

A commenter recommended removing Requirement R2 as duplicative of the TOP standards, but as explained above, that was not possible since the TOP standards are currently being reviewed. Further subpart 2.2 requires an explanation for why a voltage schedule cannot be met, and no other standard covers that. In addition, subpart 2.3 provides a caveat that a conversion methodology maybe provided during an audit, and auditor should not use the VAR standard to require high-side monitoring for GOPs. This is also not duplicated in any other standard.

AVR Modes

Some commenters recommended revisions to the standard to allow for multiple voltage control modes. The SDT agreed, and Requirement R1 was revised to allow GOPs to operate with the AVR in-service and in a mode different from "voltage controlling" if instructed by the TOP.

ERCOT RC Functions

Some commenters asked that the standard account for ERCOT nuances where the RC functions like a TOP in other areas. The VAR SDT determined the standard did not need to be modified because in ERCOT, RCs and TOPs have already determined their roles through contractual arrangements.

Deviations from Voltage Schedule

Some commenters recommended providing a minimum threshold for notifications when deviations to voltage schedules occur. The time-frames recommended were rolling averages (30 or 60 minutes), but the VAR SDT could not make these modifications. A smaller window was proposed in the last unsuccessful draft of VAR-002-3, and the industry could not reach a consensus on the right window for the entire continent. Thus, VAR-001-4 was modified to allow the TOPs to set notification timeframes based on the system needs. Also, NERC staff opposed creating too large of non-compliance window due to Reliability concerns.

Exemptions

Some commenters asked for more clarity on what qualifies as an exemption. In VAR-001-4 the TOP may set the exemption criteria for GOPs. TOPs must notify the GOPs when the exemption criteria has been met by the GOPs.

Dispersed Generation

Some commenters asked that VAR-002-3 be amended to account for dispersed generation. However, the VAR SDT is deferring to the Dispersed Generation team currently evaluating standards that would need certain updates. The VAR SDT has provided a copy of the proposed VAR-002 changes to the Dispersed Generation team.

Implementation/Effective Date

One commenter was concerned about the effective date being too soon; however, that commenter did not realize the standard will not go into effect in the United States until the first quarter after regulatory approval. The standard will not go into effect immediately after the approval by the NERC Board of Trustees.

Changing 15 minutes to 30 minutes in Requirements R3 and R4

Some commenters recommended allowing GOPs to have the full 30 minutes to correct a status or reactive capability change, and the VAR SDT agreed that this change will simplify the standard and maintain reliability. Therefore, Requirements R3 and R4 have been amended to allow the full 30 minutes to correct an issue before notifying the TOP.

One commenter also questioned the need for certain status changes. The VAR SDT re-affirmed the need for status change notifications, and the TOPs on the drafting team confirmed they should be notified when an AVR is in service and when it comes back on after an issue in order to know what resources are available in an area.

Requirement R6 Functional Entity

Some commenters questioned why Requirement R6 applies to GOs, while subpart R6.1 applies to GOPs. The VAR SDT agreed and determined that GOs are the appropriate entity for coordinating when a unit is taken offline to make the tap changes. Therefore, subpart R6.1 has been modified to apply to GOs.

VSL

Some commenters recommended changes to the VSLs to add back in time gradations for violations. However, the VAR SDT removed many of the time elements from the VSLs because those timing elements did not have a technical basis and appeared arbitrary.

Telemetering/Notifications

Some commenters asked that telemetering count for compliance purposes when making notifications to the TOP. The notification requirements are set in VAR-001-4, but the standard does not preclude telemetering in any form.

Compliance Input

Comments were received regarding the timing of the posting of a Reliability Standards Audit Worksheet (RSAW). NERC is providing a draft RSAW that will address compliance assessment questions for the draft standard within fifteen days of posting a revised VAR-002-3.

Attachment A – SDT Members Contact Information

	Participant	Entity
Chair	Bill Harm	PJM
Member	Stephen Hitchens	Bonneville Power Authority
Member	Sharma Kolluri	Entergy
Member	Hari Singh	Xcel
Member	Joshua Pierce	Southern Company
Member	Hamid Zakery	Calpine
Observer	Joe Seabrook	Puget Sound Energy
Observer	Scott Berry	Indiana Municipal Power Authority
Observer	Brian Buckley	Tampa Electric Company
Observer	Mike Swearingen	Tri-County Electric Cooperative

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments Summary

Project 2013-04 Voltage and Reactive Control

October 11, 2013

RELIABILITY | ACCOUNTABILITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326

Table of Contents

Introduction

The Project 2013-04 standard drafting team (SDT) thanks all commenters who submitted comments on the draft VAR-001-4 and VAR-002-3 standards. These standards were posted for a 45-day public comment period from August 23, 2013 through September 3, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 78 sets of responses, including comments from approximately 211 different people from approximately 124 companies representing all 10 Industry Segments.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Consideration of Comments

Purpose

The VAR SDT appreciates the comments from industry regarding the VAR-001-4 and VAR-002-3 standards. All comments were reviewed carefully by the SDT and changes were made to the standard accordingly. While all comments were reviewed, the new Standards Process Manual (SPM) does not require responses to each individual comment when a successive ballot is needed. However, this document provides a summary of responses to comments. The following pages will provide a summary of the comments received and how the comments were addressed by the VAR SDT. If a specific comment was not addressed in the summary of comments, please contact the NERC Standards Developer or one of the SDT members to discuss.

Process Comments

Several commenters expressed concern that the simultaneous posting of the Standards Authorization Request (SAR) and the pro forma standard for initial comment and ballot was outside the scope of the Standards Process Manual (SPM). The SDT notes that, although this action was authorized by the NERC Standards Committee, NERC received an appeal of the SPM, which has been resolved. The SDT notes the process issue is outside the purview of the SDT.

Separate Postings / Merging Standards

Some commenters suggested merging the VAR standards or balloting the standards separately. Based on industry feedback and the difference in the timing of audits, the VAR SDT decided to keep the standards separate. However, the team agreed that it would be beneficial to ballot the standards separately.

WECC Variance

Some commenters were confused because the applicability section includes Generator Operators (GOP) within the Western Interconnection. This is necessary because the WECC variance in VAR-001-3 is being retained.

VAR-001 Comments

Reliability Coordinator

- Several commenters objected to adding Reliability Coordinators (RC) to the VAR-001 standard. In order to clarify the role of the RC, the VAR SDT is not going to add RCs to the standard at this time because the issue of RC monitoring is presently before FERC in another filing. Therefore, the VAR SDT will address this directive at a later time, pending a FERC order on the Interconnection Reliability Operations and Coordination (IRO) standards.

Administrative Burden

- Several commenters were concerned that there would be an administrative burden for Transmission Operators (TOPs) and RCs with the new standard. However, the new standard is intended to provide a vehicle for more efficiency and better communication once the VAR-001-4 standard is implemented; for example, fewer unnecessary phone calls/notifications will be made to the TOP once the TOP provides notification requirements to the GOPs. In addition, the standard has been modified to provide schedules to adjacent TOPs and RCs only upon request. This should alleviate some of the administrative burden involved with communicating schedules. Also, the SDT has opted to not add RCs to the standard at this time. The directive regarding RC monitoring will be addressed after order on the pending IRO standards has been issued.

Vagueness of VAR-001

- Several commenters said that several aspects of VAR-001-4 were “vague.” It was not clear to many what an “assessment” entailed and how compliance would be evaluated for many of the VAR-001-4 requirements. The revised VAR-001-4 is simplified and has clarified the standard by removing terms like "assessment," "implement," and "policies and procedures."

Duplication of Other Standards

- Several commenters stated the VAR-001-4 requirements were duplicative of several other standards. The VAR SDT determined that there is some overlap, particularly with regard to Requirements R1 and R5 of the initial posting. Requirement R5 of the initial posting has been removed, and Requirement R1 has been revised to simply require the TOP to specify voltage schedules. However, in order to show that System Operating Limits (SOLs) will encompass the details for voltage limits, both SOLs and Interconnection Reliability Operating Limits (IROLs) are referenced.

Interconnection Point

- Some commenters took issue with the phrase "at the interconnection point between the generator facility and Transmission Owner's facility." In order to allow the TOP the discretion for how to provide a voltage schedule, the phrase has been removed.

Technically Justified Schedules/Tolerance Bands

- Several commenters expressed concern because the standards did not require technically justified schedules or tolerance bands. In order to the balance the needs for maintaining a TOP's ability to monitor its system, the SDT did not add language requiring a "technically justified" schedule. Instead, the TOPs are now required under VAR-001-4 to provide the criteria to the GOPs for how the schedules were determined. This would provide GOPs with the ability to review technical documentation for schedules and tolerance bands, and this would prevent a TOP from having to dispute all of its schedules.

Power System Stabilizer

- Some commenters requested that the requirement for knowing the status of Power System Stabilizers (PSS) is a duplicate of the TOP standards. The VAR SDT determined that the importance of PSS monitoring varies by region and entity, and this requirement was removed because the TOP standards allow for the monitoring of certain data specifications. This allows the areas that require monitoring of the PSS to have this action included in the TOP data specifications, but for areas that do not need to monitor for reliability, the PSS will not have to be included. PSS equipment has not been removed from VAR-002-3 notification requirements because that equipment is part of the automatic voltage regulator (AVR).

Tap Setting Changes

- Many entities commented that the tap setting changes should have an "agreed upon" timeframe for making those changes. In order to maintain the TOPs authority, the VAR SDT only modified VAR-001-4 to require TOPs to include an implementation schedule as part of the tap setting consultation. However, the standard was not modified to require a particular timeframe for when a unit must be taken off line to make a tap setting change.

VAR-002 Comments

Testing

- Some commenters suggested modifying VAR-002-3 Requirement R1 to allow for testing of a unit. The revised standard now lists testing as a time when the unit does not have to be in AVR.

Multiple AVR Settings

- A commenter requested that the standard be updated to allow for multiple AVR settings if necessary for reliability purposes. The VAR-001-4 standard has been updated to allow for the TOPs to provide very flexible exemptions based on system needs. These exemptions encompass being in various AVR settings based on the TOP's exemption criteria.

Timeframes for Notifications

- Many commenters questioned the timeframes proposed as a non-compliance window. It was very difficult to set a minimum notification requirement for the entire continent, particularly for being out of schedule, so the SDT opted to allow the TOPs to tailor when it should be notified by GOPs. Therefore, VAR-001-4 has a requirement to provide GOPs with their notification requirements for being out of schedule or tolerance based on system needs.

Monitoring and Conversion of a High-Side Schedule

- Although the VAR SDT initially added that the conversion of a high-side voltage schedule was acceptable in the measures for VAR-002-3, there were numerous comments that this needed to be a requirement. Thus, the VAR SDT added the requirement to provide conversion methodology for those units that do not have high-side monitoring capability.

Facility Ratings

- Some commenters suggested changing "Facility Ratings" to capability. The VAR SDT adopted this change.

VRFs/VSLs

- Some commenters recommended changes to the VRFs/VSLs for VAR-002-3 because they can be interpreted as being too severe with little to no reliability benefit. The VSLs have been simplified, and the VAR SDT modified the VRFs/VSLs significantly by removing several time constraints. The team reviewed the revised VSLs against the FERC order regarding VSL guidelines (123 FERC ¶ 61284).

Generator Owner

- One commenter suggested that the tap setting changes requirement should not include both the Generator Owner (GO) and GOP. However, both entities should be included. Several GOs are impacted when a unit has to come off-line, but the GOP is the one that will usually performs the actual changes.

Compliance Input

Comments were received regarding the posting of a Reliability Standards Audit Worksheet (RSAW). NERC is providing a Compliance Input document that acts as a draft RSAW and addresses compliance assessment questions for the draft standard.

Attachment A – SDT Members Contact Information

	Participant	Entity
Chair	Bill Harm	PJM
Vice Chair	Martin Kaufman	ExxonMobil Research and Engineering
Member	Stephen Hitchens	Bonneville Power Authority
Member	Sharma Kolluri	Entergy
Member	Hari Singh	Xcel
Member	Joshua Pierce	Southern Company
Member	Joe Seabrook	Puget Sound Energy
Member	Scott Berry	Indiana Municipal Power Authority
Member	Brian Buckley	Tampa Electric Company
Member	Mike Swearingen	Tri-County Electric Cooperative
Member	Hamid Zakery	Calpine

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.

Description of Current Draft

This is the second posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
Additional 45-Day Comment Period with Ballot	October/November 2013
Final Ballot	December 2013
NERC Board of Trustees Adoption	December 2013
Filing to Applicable Regulatory Authorities	December 2013

Version History

Version	Date	Action	Change Tracking
1	6/18/2007	Initial Standard is FERC approved	
2	1/10/2011	FERC approved added LSEs and Controllable Load to the standard.	
3	6/20/2013	WECC Variance is approved by FERC	

Definitions of Terms Used in the Standard

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

None.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4
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

Rationale for R1: P 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, 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 definition of SOLs must include 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.

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 Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules and associated tolerance bands 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 were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

Rationale for R2:

P 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 require the periodic voltage stability analysis because such analysis is now required pursuant to the SOL methodology in 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 P 1879.

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 Planning]*

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

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.

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 Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

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.

R4. The Transmission Operator shall specify the criteria that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements. *[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 generating unit in its area that is exempt from: 1) 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.

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.

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 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.

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules and associated tolerance bands 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 and tolerance band.

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule and 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. The evidence shall include written records, email, or voice recordings.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule and associated tolerance band. The evidence shall include written records, email, or voice recordings.

For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules and associated tolerance bands within 30 days of receiving a request by a Generator Operator.

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.

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 1 through 4 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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 Planning**	**High**	N/A	N/A	N/A	The Transmission Operator has not specified a system voltage.
R2	**Real-time Operations, Same-day Operations, and Operational 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 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.	The Transmission Operator does not have exemption criteria.
R5	**Operations Planning**	**Medium**	N/A	The Transmission Operator provides the criteria for voltage schedules after 30 days of request.	The Transmission Operator provides voltage or Reactive Power schedules to some, but not all, Generator Operators.	The Transmission Operator does not provide voltage or Reactive Power. Or The Transmission Operator did not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule.
R6	**Operations Planning**	**Lower**	Either the technical justification or timeframe are not provided.	N/A	N/A	Neither the technical justification nor the timeframe are provided.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R3 and R4. Please note that Requirement R3 is deleted and R4 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: Medium] [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.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.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.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.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.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.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.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.

Description of Current Draft

This is the second posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.~~This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.~~

Anticipated Actions	Anticipated Date
~~SAR Authorized by the Standards Committee~~	~~July~~
Additional 45--Day ~~SAR~~ Comment Period with~~and Initial~~ Ballot ~~Open~~	October/November 2013~~July~~
~~Nomination Period Opens~~	~~July~~
~~Standard Drafting Team Appointed~~	~~July~~
~~Initial Comment and Initial Ballot Closes~~	~~August~~
Final Ballot ~~Opens~~	December 2013~~October~~
~~Final Ballot Closes~~	~~October~~
NERC Board of Trustees~~BOT~~ Adoption	December 2013~~November~~
Filing to Applicable Regulatory Authorities	December 2013

~~Effective Dates~~

~~In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard~~

~~shall become effective on the first day of the first calendar quarter after Board of Trustees approval.~~

Version History

Version	Date	Action	Change Tracking
1	6/18/2007	Initial Standard is FERC approved	
2	1/10/2011	FERC approved added LSEs and Controllable Load to the standard.	
3	6/20/2013	WECC Variance is approved by FERC	

Definitions of Terms Used in the Standard

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

None.

A. Introduction

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

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

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.** Reliability Coordinators~~

   ~~4.3.~~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.

Requirements and Measures

~~**Rationale for R1:** This requirement will allow each Transmission Operator (TOP) to establish its own policies and procedures, and the criteria for periodic updates will be individualized based on the stability of each TOP's regions. The language is refined to show that coordination with neighboring TOPs is required. It also states TOP shall provide data to the Reliability Coordinator (RC) for its monitoring functions to respond to address the FERC directive in P 1855 of Order No. 693, which directed NERC to add RC monitoring to the VAR standards. P 1868 requires NERC to add more "detailed and definitive requirements to include more detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins)."~~

Rationale for R1: P 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, 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 definition of SOLs must include 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.

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~~have documented policies or procedures that are implemented to establish, monitor, and control voltage levels and Reactive Power flows (Mvar flows) within limits as defined below~~. *[Violation Risk Factor: High] [Time Horizon: Operational Planning~~Operations~~]*

~~**1.1.** These documented policies or procedures shall include criteria used in system assessments. The criteria for the assessments shall include established steady-state limits, voltage stability limits and associated operating margins, and voltage schedules along with associated tolerance bands.~~

1.1. Each Transmission Operator shall provide a copy of the voltage schedules and associated tolerance bands to its Reliability Coordinator and ~~these documented policies or procedures to~~ adjacent Transmission Operators within 30 calendar days of a request.

~~**1.2.** Each Transmission Operator shall provide a copy of these documented policies or procedures to its Reliability Coordinator.~~

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.

~~The Transmission Operator shall have evidence of documented voltage schedules and associated tolerance bands.~~

For part~~policies or procedures as specified in Requirement~~ 1.1~~ As stated in R1~~, the Transmission Operator shall have~~policies and procedures must detail how criteria for steady-state and voltage stability limits are used in the Transmission Operator's assessments of the system. In order to demonstrate the Transmission Operator is implementing the policies or procedures, the Transmission Operator must be able to provide~~ evidence that the~~proves~~ voltage schedules~~ and associated tolerance bands~~~~is currently being monitored. Such evidence may include, but is not limited to: 1) proof that points are telemetered, 2) alarms are functioning, and 3) during events of low or high voltage the policies and procedures are being followed to respond to control voltage levels. The Transmission Operator must also provide evidence that the policies or procedures~~ were provided to its Reliability Coordinator and ~~communicated to~~ adjacent Transmission Operators within 30 days of a request.~~and to its Reliability Coordinator.~~ Evidence may include, but is not limited to, emails, website postings, and meeting minutes.~~ Simply posting a copy of the policies or procedure on a public website is not sufficient if the Transmission Operator and Reliability Coordinator were not notified as to where to find the policies or procedures.~~

~~**Rationale for R2:**~~

~~P 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically. The informal ad hoc group and industry participants concluded that the best models and tools are the ones that have been proven over time, and that the requirement should not require any utility to purchase new online simulations tools. Therefore, the new requirement does not specify when to use online tools. The sub-requirements detail the real-time and day-ahead assessments necessary under R1. The existing VAR-001 also requires a list of sufficient reactive resources; this was retained in the proposed requirement as FERC determined in a letter order that this list answered the directive in P 1868 to detail the list of "sufficient reactive resources." Controllable load is specifically included to answer FERC's directive in P 1879.~~

Rationale for R2:

P 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 require the periodic voltage stability analysis because such analysis is now required pursuant to the SOL methodology in 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 P 1879.

R2. Each Transmission Operator ~~and Reliability Coordinator~~ shall schedule~~perform assessments on their respective areas in order to ensure~~ sufficient reactive resources ~~are available for scheduling~~ to regulate~~maintain~~ voltage levels~~stability~~ under normal and Contingency~~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. ~~in order to provide the voltage levels as defined in Requirement R1.~~ *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

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

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.

R3. Each Transmission Operator shall operate or direct the Real~~real~~-time operation of ~~-~~devices ~~necessary~~ to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day* ~~necessary to regulate transmission voltage and reactive flow which may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; controllable load; and, if necessary, load shedding, to maintain system voltages within established limits.~~*Operations, and Operational Planning]*

~~**3.1.** As a result of the assessments, each Transmission Operator shall ensure that sufficient reactive resources have been scheduled to meet acceptable day-ahead voltage limits identified in Requirement R1. Sufficient reactive resources may include, but is not limited to reactive generation scheduling; transmission line and reactive resource switching; and controllable load.~~

~~M1.~~M3. Each Transmission Operator ~~and Reliability Coordinator~~ shall have evidence that actions~~of current or past studies used to schedule sufficient reactive resources. Each Transmission Operator shall also provide proof that additional resources~~ were taken to operate ~~scheduled when necessary. During a real-time event where voltage must be adjusted, a Transmission Operator shall show evidence to show directions were given to adjust the operation of~~ capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3)~~operate within new tolerance bands or to~~ make manual adjustments. ~~if necessary. Transmission Operators shall also have evidence to show proof of directing new resources to come online. Those resources can include, but is not limited to capacitor banks, switching, adjusting controllable load, and when necessary load can be shed. For the day-ahead scheduling, Transmission Operators shall provide copies of provide day-ahead studies used to schedule enough resources to meet expected voltage requirements.~~

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 R4.**~~

~~These exemptions offer TOPs the option to exempt certain generators during maintenance or system events when those units are not able to maintain voltage schedules. Sub-requirements containing an exemption list were removed from the existing standard because this created more compliance issues with regard to how often the list would be updated and maintained.~~

R4. The Transmission Operator shall specify the criteria that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1,~~4~~ and any associated notification requirements. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

If~~In the event~~ a Transmission Operator determines that~~approves~~ a generator has satisfied~~as satisfying~~ 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~~The~~ Transmission Operator shall also have evidence to show that, for each generating unit in its area that is exempt from: 1) 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. ~~following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3. Temporary exemptions maybe provided to generators during scenarios where notifications/communications are not necessary due to a system event that prevents a Generator Operator from maintaining a schedule. Similarly, when an Automatic Voltage Regulator (AVR) is malfunctioning, which prevents a Generator Operator from maintaining a voltage schedule and tolerance band, temporary exemptions may be provided. For temporary exemptions, evidence showing the exemptions were granted must be provided. If the exemptions were given verbally from the Transmission Operator, the phone recordings or emails commemorating the phone~~

~~call must be provided. For temporary exemptions, the evidence of communication must also include the timeframe for how long the exemption will last.~~

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 R5:**~~

~~The new requirement adds "tolerance band" in order to provide more detailed information when establishing limits.~~

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range~~,~~ or a target value with an associated~~and~~ tolerance band) ~~(~~at either the high voltage side or low voltage side of the Generator Step-Up transformer at the ~~TOP's discretion) at the interconnection point between the generator facility and the~~ Transmission Operator's discretion~~Owner's facilities to be maintained by each generator~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule ~~and 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.

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules and associated tolerance bands 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 and tolerance band.

For part 5.1, theThe Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule and tolerance band ~~as specified in Requirement 4~~ to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted. The~~. For real-time directives,~~ evidence shall~~may~~ include written records, email, or voice recordings. ~~recorded phone logs.~~

For part 5.2,

~~**R6.** The Transmission Operator shall know~~ the ~~status of all transmission Reactive Power resources, automatic voltage regulators, and power system stabilizers in their system. *[Violation Risk Factor: Medium] [Time Horizon: Operations]*~~

~~The~~ Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule and associated tolerance band. The evidence shall~~to show Reactive Power resources are being monitored. Evidence may~~ include written records, email, or voice recordings~~, but is not limited to screen shots of EMS/SCADA data, alarms, and phone logs. In the event the monitoring system does not work, each Transmission Operator should have a protocol in place to show these resources are being monitored~~.

For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules and associated tolerance bands within 30 days of receiving a request by a Generator Operator.

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.

~~**Rationale for R6:**~~

~~Since power system stabilizers (PSS) equipment is not highlighted in any other standard, the VAR standard is the appropriate place to ensure the equipment is being monitored. This requirement is not duplicative of the TOP standards because the voltage regulators and power system stabilizer are highlighted.~~

~~**R7.**~~**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]*

~~M2.~~**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~~means~~ 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 1 through 4 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

As defined in the NERC Rules of Procedure, "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*~~**Operational Planning**	**High**	N/A~~The Transmission Operator has documented criteria for assessments, but has provided a copy to only one of the parties that should have received a copy (either a neighboring TOPs or its RC).~~	N/A~~The Transmission Operator has documented policies and procedures, but has not provided copies to either the neighboring TOPs or its RC.~~	N/A~~The Transmission Operator has documented policies or procedures, but none of the sub-requirements were followed.~~	The Transmission Operator has not specified a system voltage schedule.
R2	**Real-time Operations, Same-day Operations, and Operational Planning**	**High**	N/A	N/A~~The Transmission Operator only performs day-ahead assessments and only schedules day-ahead resources.~~	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.~~N/A~~	The Transmission Operator does not schedule~~perform assessments and therefore does not have policies and procedures implemented to have~~ sufficient reactive resources as necessary to avoid violating an IROL~~Mvars. A lack of real-time operations is also severe~~.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	**Real-time Operations, Same-day Operations, and Operational Planning**	**High~~Lower~~**	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. ~~N/A~~	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL~~have exemption criteria~~.
R4	**Operations Planning**	**Lower~~Medium~~**	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence~~provides voltage or Reactive Power schedules to only some~~ of the notification~~GOPs~~.	The Transmission Operator does not have exemption criteria~~provide voltage or Reactive Power schedules and tolerance bands at all~~.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	**Operations Planning**	**Medium~~Lower~~**	N/A	The Transmission Operator provides ~~is unaware of~~ the criteria for voltage schedules after 30 days of request~~status in a stable area~~.	The Transmission Operator provides voltage or Reactive Power schedules to some, but~~does~~ not all, Generator Operators~~know the status of important equipment in weaker areas that were identified in assessments as part of R1~~.	The Transmission Operator does not provide voltage or Reactive Power schedules-. Or The Transmission Operator did not provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule. ~~N/A~~
R6	**Operations Planning**	**Lower**	Either the technical justification or timeframe are not provided.	~~Neither the technical justification nor the timeframe are provided.~~N/A	N/A	~~N/A~~Neither the technical justification nor the timeframe are provided.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in ~~Regional Variance for~~ the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R3 and R4. Please note that Requirement R3 is deleted and R4 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: Medium] [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.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.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.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.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.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.A.13~~M.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~~VAR-001-3 is retained~~.

[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.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please review~~see~~ the rationale provided~~VAR White Paper~~ for each requirement~~further technical information~~.

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.

Description of Current Draft

This is the second posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
Additional 45-Day SAR Comment Period with Ballot	October/November 2013
Final Ballot	December 2013
NERC Board of Trustees Adoption	December 2013
Filing to Applicable Regulatory Authorities	December 2013

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

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

None.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-3
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**

    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, VAR-002-3 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

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 voltage controlling mode. 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.

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) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) 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 the automatic voltage control mode 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 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. Such evidence must 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 exempted, the Generator Operator shall also have evidence that it 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.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates the system to maintain a voltage schedule 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 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. A new part 2.3 has been added to detail that each GOP shall monitor voltage based on 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.

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 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 directed by the Transmission 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.

2.2. When directed 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 unit 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 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 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 directed by the Transmission Operator.

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

For part 2.3, for units that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.

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. Such notifications provided little to no benefit to reliability. Fifteen (15) 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 or capability change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. The 15-minute window should resolve most issues.

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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator. *[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 the change identified in Requirement R3. If the status has been restored within the first 15 minutes, no notification is necessary; therefore, if a status change lasts more than 15 minutes, the GOP must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

Rationale for R4:

This requirement has been bifurcated from the earlier 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 already in non-compliance situations by the time it is known that a reactive capability change has taken place.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes after 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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of the recognition of a reactive capability change identified in Requirement R4. If the capability has been restored within the first 15 minutes, no notification is necessary; therefore, if a capability change lasts more than 15 minutes, the Generator Operator must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

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 amount of VARs produced by a unit can be affected. The original sub-requirement 4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed.

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 transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirements R5 part 5.1.1 through part 5.1.3.

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 amount of VARs produced by a unit can be affected.

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 Operator cannot comply with the Transmission Operator's specifications, the Generator Operator 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 as identified in Requirement R6. The Generator Operator 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 as identified in 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:

As defined in the NERC Rules of Procedure, “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 responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The responsible entity did not have conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The responsible entity did not maintain voltage or Reactive schedule as directed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The responsible entity did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The responsible entity 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 responsible entity did not make the notification within 30 minutes.

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 responsible entity did not make the notification within 30 minutes.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirements R5 parts 5.1.1 and 5.1.2 and 5.1.3.	The responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirements R5 parts 5.1.1 and 5.1.2 and 5.1.3.
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 Operator failed to perform the tap changes, and the

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Generator Operator did not provide technical justification for why it cannot comply with the Transmission Operator directive.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19~~XX~~, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.

Description of Current Draft

This is the second posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.~~This draft standard is concluding informal development and will move to formal development when authorized by the Standards Committee.~~

Anticipated Actions	Anticipated Date
~~SAR Authorized by the Standards Committee~~	~~July~~
Additional 45-~~-~~Day SAR Comment Period with~~and Initial~~ Ballot ~~Open~~	October/November 2013~~July~~
~~Nomination Period Opens~~	~~July~~
~~Standard Drafting Team Appointed~~	~~July~~
~~Initial Comment and Initial Ballot Closes~~	~~August~~
Final Ballot~~ Opens~~	December 2013~~October~~
~~Final Ballot Closes~~	~~October~~
NERC Board of Trustees~~BOT~~ Adoption	December 2013~~November~~
Filing to Applicable Regulatory Authorities	December 2013

~~Effective Dates~~

~~In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.~~

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

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

None.

A. Introduction

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

2. **Number:** VAR-002-3

3. **Purpose:** To ensure generators provide reactive support and voltage control, ~~necessary to ensure voltage levels, reactive flows, and reactive resources are maintained~~ within generating~~applicable~~ Facility capabilities, in order~~Ratings~~ to protect equipment and maintain~~the~~ reliable operation of the Interconnection.

4. **Applicability:**

   4.1. Generator Operator

   4.2. Generator Owner

5. **Effective Dates**

   ~~All requirements~~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, VAR-002-3 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

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 voltage controlling mode. 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 R1:** This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in voltage controlling mode. The measure has been updated include some of the evidence that can be used for Compliance purposes.~~

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) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) 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]~~[2]~~ ~~or~~ shutdown,[3] or testing[4] 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 the automatic voltage control mode for a reason other than start-up, ~~or~~ 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 as specified in Requirement R1~~1~~. 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~~automatic voltage regulator~~ 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. Such evidence must 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 exempted, the Generator Operator shall also have evidence that it 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] 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.~~

[3] 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.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates the system to maintain a voltage schedule 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 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. A new part 2.3 has been added to detail that each GOP shall monitor voltage based on 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 R2:**~~

~~R2 details how a Generator Operator (GOP) operates the system to a maintain voltage schedule and when the GOP is expected to notify the Transmission Operator (TOP). Sub-requirement 2.1 provides guidance on a non-compliance window in the event a unit is deviating from schedule, and the GOP must notify the TOP if it is unable to return to schedule. Thus, the non-compliance window allows for notifications when a unit is unable to provide additional VAR support (e.g., when hitting an operational limit) or when the unit is too small to raise voltage. In both instances, the TOP may then provide some type of temporary exemption as outlined in VAR-001.~~

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[5] (within each generating Facility's capabilities[6]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage schedule provided by the Transmission Operator.~~applicable Facility Ratings[7]) as directed by the Transmission Operator.~~ *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~**2.1.** If a GOP drifts out of schedule, each Generator Operator shall notify its associated Transmission Operator within 15 minutes when both of the following conditions are met: 1) the GOP is operating outside of the prescribed voltage or Reactive Power schedule tolerance band[8] for 15 minutes; and 2) the GOP is no longer able to return to its voltage or Reactive Power schedule.~~

~~2.2.~~2.1. When a generator's AVR~~automatic voltage regulator~~ 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 directed by the Transmission Operator.

~~2.3.~~2.2. When directed 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 unit 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 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 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 directed by the Transmission Operator.

---

[5] 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~~ establishing a tolerance band within which the target value is to be maintained during a specified period~~.

[6] 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.

~~[7] When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this may lead to a change in the associated Facility Ratings.~~

~~[8] GOPs monitor and control voltage based on their equipment limitations. GOPs will monitor their voltage or Reactive Power schedule tolerance bands either at the high-side or low-side/terminal voltage.~~

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

~~**M2.**~~ For part 2.3, for units that do not monitor the voltage at the location specified on the voltage schedule the Generator Operator shall document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.~~Generator Operators will still make all attempts to operate within the tolerance bands provided by the TOP, but natural drifting may occur. In instances where there is an event occurring to pull a unit out of the tolerance band, the Generator Operator will not be held in non-compliance with this requirement if the sub-requirements 2.1, 2.2, and 2.3 are met. In order to identify when a unit is deviating from its schedule, GOPs will monitor voltage based on existing equipment at its facility. Therefore, GOPs have the option to operate on a voltage schedule on either the high-side or convert the high-side schedule to a low-side schedule at the GOP's discretion. For units that monitor on the low-side/terminal voltage, Generator Operators shall provide evidence of the method of conversion from the high-side schedule to low-side monitoring. For sub-requirement 2.1, most units will not be able to return to schedule due to a limiting factor. Such limiting factors may include, but are not limited to: 1) terminal voltage, 2) bus voltage, 3) equipment temperature, 4) transformer, 5) auxiliary equipment, 6) Volts/Hz limits, and 7) excitation or regulator limits. GOP shall have evidence to show compliance with requirement R2 by providing 1) Communications with the TOP when the Generator Operator was operating outside of the prescribed voltage or Reactive Power schedule tolerance band for 30 minutes or less (the 30 minutes allow for 15 minutes to call and 15 minutes to be outside of the tolerance band) AND Generator Operator is no longer able to return to its voltage or Reactive Power schedule; 2) Generator Operator implemented an alternative method to control reactive output when the AVR was out-of-service or unavailable; 3) compliance with directive to modify voltage or a notification that the directive could not be met. Evidence may include, but is not limited to Generator Operator logs, SCADA data, phone logs, and any other alarming notifications that would alert the Transmission Operator that both conditions were met. Timing for Requirement R2.1 is crucial, and Generator Operators are expected to begin timing an event as soon as the unit is operating outside of the tolerance band. Further, voltage documentation during a system event maybe requested by an auditor to show measures were taken to bring the unit back into schedule.~~

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. Such notifications provided little to no benefit to reliability. Fifteen (15) 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 or capability change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. The 15-minute window should resolve most issues.

~~**Rationale for R3:**~~

~~This requirement has been modified to reduce the number of violations for when an AVR goes out-of-service and then comes back in-service. Fifteen (15) minutes have been built into the requirement to allow a Generator Operator time to resolve an issue before having to notify the Transmission Operator of a status or capability change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. The 15-minute window should resolve most issues, and further trouble-shooting will probably be required if the status change is unresolved within 15 minutes.~~

R3. Each Generator Operator shall notify its associated Transmission Operator of a status ~~or capability~~ change on the AVR,~~any generator Reactive Power resource, including the status of each automatic voltage regulator and~~ power system stabilizer, or alternative voltage controlling device ~~and the expected duration of the change in status or capability~~ within 30 minutes of the change. If the status has been restored within the first 15 minutes of such change, then there is no need to notify~~call~~ the Transmission Operator~~TOP~~. *[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 of~~ the change~~changes~~ identified in Requirement R3~~3~~. If the status has been restored within the first 15 minutes, no notification~~call~~ is necessary; therefore, if a status ~~on Reactive Power resource has changed, and that~~ change lasts more~~greater~~ than 15 minutes, the GOP must notify its associated Transmission Operator~~TOP~~ within 30 minutes of when the change first occurred.

~~**Rationale for R4:**~~

~~This requirement and corresponding measure language has been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.~~

Rationale for R4:

This requirement has been bifurcated from the earlier 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 already in non-compliance situations by the time it is known that a reactive capability change has taken place.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes after 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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of the recognition of a reactive capability change identified in Requirement R4. If the capability has been restored within the first 15 minutes, no notification is necessary; therefore, if a capability change lasts more than 15 minutes, the Generator Operator must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

Rationale for R5:

This requirement and corresponding measure language has been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

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 amount of VARs produced by a unit can be affected. The original sub-requirement 4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed.

~~R4.~~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]*

~~4.1.~~5.1. For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:

~~4.1.1.~~5.1.1. Tap settings.

~~4.1.2.~~5.1.2. Available fixed tap ranges.

~~4.1.3.~~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 transformers and auxiliary transformers as required in Requirements R5 part 5~~4~~.1.1 through part 5~~4~~.1.3.

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 amount of VARs produced by a unit can be affected.

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

~~5.1.~~6.1. If the Generator Operator cannot~~can't~~ comply with the Transmission Operator's specifications, the Generator Operator 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 as identified in Requirement R6~~5~~. The Generator Operator shall have evidence that it notified its associated Transmission Operator when it could not~~couldn't~~ comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement R6 part 6~~5~~.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~~means~~ 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:

As defined in the NERC Rules of Procedure, "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~~The~~ responsible entity did not operate each generator in the automatic voltage control mode and failed to notify the Transmission Operator as identified in Requirement R1.
~~R2~~	~~Real-time Operations~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not perform any of the sub-requirements.~~
~~R3~~	~~Real-time Operations~~	~~Medium~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not make the notification within 30 minutes.~~
R2~~R4~~	**Real-time Operations**	**Medium~~Lower~~**	N/A ~~When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for up to and including 45 minutes.~~	N/A~~When directed by the Transmission Operator to maintain the generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 45 minutes up to and including 60~~	The responsible entity did not have conversion methodology when it monitors at a location different from the schedule provided by the Transmission Operator.~~When directed by the Transmission Operator to maintain the~~	The responsible entity did not maintain voltage or Reactive schedule as~~When~~ directed by the Transmission Operator and did not make ~~to maintain~~ the necessary notifications required by the Transmission Operator~~generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 75 minutes~~. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				~~minutes.~~ ~~OR~~ ~~When a generator's automatic voltage regulator is out of service, the Generator Operator failed to use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.~~ ~~OR~~ ~~The Generator Operator failed to provide an explanation of why the voltage schedule could not be met.~~	~~generator voltage or reactive power schedule the Generator Operator failed to meet the directed values for more than 60 minutes up to and including 75 minutes.~~	The responsible entity did not have an operating AVR, and the responsible entity did not~~When a generator's automatic voltage regulator is out of service, the Generator Operator failed to~~ use an alternative method for controlling voltage. OR The responsible entity did not modify~~to control the generator~~ voltage when directed, and the responsible entity did not~~and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator and the Generator Operator failed to~~ provide any~~an~~ explanation. ~~of why the voltage schedule could not be met.~~
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The responsible entity did not make the notification within 30 minutes.

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 responsible entity did not make the notification within 30 minutes.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The responsible entity failed to provide to its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirements R5 parts 5.1.1 or 5.1.2 or 5.1.3.	The responsible entity failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirements R5 parts 5.1.1 and 5.1.2 and 5.1.3.
R6~~R5~~	**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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Generator Operator~~GOP~~ failed to perform the tap changes, and the Generator Operator~~GOP~~ did not provide technical justification for why it cannot comply with the Transmission Operator~~TOP~~ directive.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please review~~see~~ the rationale provided~~VAR White Paper~~ for each requirement. ~~further technical information.~~

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001-4 and VAR-002-3

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 – All requirements 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, VAR-001-4 and VAR-002-3 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.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements, the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001 and VAR-002

Approvals Required

VAR-001-4 – Voltage and Reactive Control

VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals

There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms

None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

~~Reliability Coordinators~~

Applicable Facilities

N/A

Conforming Changes to Other Standards

None

Effective Dates

VAR-001-4 and VAR-002-3 – All requirements ~~– In those jurisdictions where regulatory approval is required, this 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 ~~regulatory approval~~ or as otherwise provided for in a jurisdiction where approval by an~~made effective pursuant to the laws~~ applicable ~~to such ERO~~ governmental authority~~authorities. In those jurisdictions where no regulatory approval~~ is required for a~~, this~~ standard to go into effect. Where approval by an applicable governmental authority is not required, VAR-001-4 and VAR-002-3 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~~approval~~.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements~~a documented policy or procedure for assessments~~,~~;~~ the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular j~~J~~urisdiction in which the new standards are becoming effective.

Unofficial Comment Form

Project 2013-04 Voltage and Reactive Control (VAR) Revisions

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft VAR-001-4 and VAR-002-3 standards. The electronic comment form must be completed by 8:00 p.m. ET by **November 25 , 2013**.

If you have questions please contact Soo Jin Kim via email or by telephone at 404-446-9742.

The project page may be accessed by clicking here.

Background Information

When the first versions of the VAR standards were approved in FERC Order No. 693,[1] the Commission also issued FERC issued several directives with regard to how to improve the standard. Each of the outstanding directives are explained in detail in the technical white paper (see project page).

The informal consensus building for VAR began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, remove paragraph 81 candidates, and implement results-based approaches. A discussion of the ad hoc group's consensus building and collaborative activities are also included in the technical white paper.

Project 2013-04 posted an initial draft for comment and ballot form July 19, 2013 to September 3, 2013. Although the VAR standards did not pass, the industry provided numerous helpful coments, and the standard drafting team made significant revisions based on the stakeholder input.

The proposed VAR-001 answers most of the FERC directives from Order No. 693, and the VAR-002 has been modified to address certain compliance issues today. Some directives are not being addressed at this time pending FERC determiniations in related filings, but those directives may be revisted during a phase 2 of this project. This posting is now soliciting comment on the revised VAR-001 and VAR-002 standards.

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

[1] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Question

1. Although FERC directed NERC to provide more details on “established limits,” the VAR standards development team determined that the FAC and TOP standards provide explicit requirements on voltage limits. Further, the definition of a System Operating Limit requires Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits) to be included. Is it clear that the specifics with regard to voltage limits are to be determined and monitored as part of operating within System Operating Limits and Interconnection Reliability Operating Limits?

☐ Yes
☐ No

Comments:

2. Several requirements were removed because they duplicated other standards. Do you agree with this approach? Do you have any specific questions or comments relating to the requirements in the revised VAR-001-4?

☐ Yes
☐ No

Comments:

3. VAR-002 was modified to remove several compliance issues, and in order to address burdensome notification requirements, the VAR-001 standard has been modified to allow each TOP to tailor notification requirements based on system/area needs. Do you agree with these revisions?

☐ Yes
☐ No

Comments:

4. The VRFs/VSLs for VAR-002 were modified to remove arbitrary time requirements. Do you have any specific comments or questions about the new VSLs/VRFs?

Comments:

Compliance Operations

Draft Reliability Standard Compliance Guidance for VAR-001-4 and VAR-002-3
October 21, 2013

Introduction

The NERC Compliance department (Compliance) worked with the VAR standard drafting team (SDT) to review the proposed standards VAR-001-4 and VAR-002-3. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the VAR SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

VAR-001 and VAR-002 Questions

Question 1

How will compliance determine if sufficient reactive resources were scheduled as part of VAR-001-4 Requirement R2?

Compliance Response to Question 1

For VAR-001-4 Requirement R2, an auditor would review the studies that a TOP used to schedule resources to see that the studies show whether new resources should be brought online, or if the resources online are sufficient to regulate voltage levels. An auditor may observe a TOP reviewing the study and scheduling live and may pull samples from various time periods to determine whether a TOP scheduled resources as required in the study.

Question 2

Is it clear that VAR-001-4 Requirement R4 allows for exemptions, for any duration, from: 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements?

Compliance Response to Question

It is clear that VAR-001 Requirement R4 allows for any combination of exemptions for generator operators from 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements, as long as the

exemption meets the criteria specified by the TOP. An auditor will not look for any pre-authorization from the TOP; rather an auditor will verify that the generator operator has met the criteria set forth by the TOP.

Question 3

Tolerance bands apply to a set voltage or Reactive Power number with a +/- percentage as the tolerance band. The voltage range or Reactive Power range is a high and low number that a Generator Operator is expected to operate within for reliability purposes. With regard to VAR-001-4 Requirement R5, is it clear that when a voltage range or Reactive Power range is provided as a schedule, a tolerance band is not expected to also be provided?

Compliance Response to Question 3

Yes, it is clear based on VAR-001-4 Requirement R5 that a voltage or Reactive power schedule can be either: 1) a target number with a tolerance band, OR 2) a voltage or Reactive Power range to operate within. An auditor would not expect to see a tolerance band provided with an operating range for voltage or Reactive Power.

Question 4

With regard to VAR-002-3, will generators receive a violation for instances where a system event is affecting system voltage, but the generators made the appropriate conversions and set the AVRs to meet the original schedule provided by the TOP?

Compliance Response to Question 4

No, the generator operators can only be responsible for maintaining the schedule provided by the TOP based on existing facility equipment. In the event that a generator operator does not have the equipment to have visibility of high-side system voltage, the GOP will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the GOP does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the generator operator is non-compliant. However, if the TOP provides a new directive or schedule, the GOP is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the generator operator is expected to comply pursuant to VAR-002-3.

Question 5

Related to VAR-002-3, generators can monitor voltage on either the low side and high side of the GSU (depending on equipment limitation) and the “number” being monitored by the Generator will not always equate to the number provided by the TOP. Is it clear that VAR-002 Requirement R2, part 2.3 only wants a conversion of the schedule provided to the number monitored? Is it clear that there should not be a violation if the schedule does not match the number being monitored on the low side as long as there is a documented conversion?

Compliance Response to Question 5

The Generator should be able to provide documentation that identifies the “number” being monitored and the calculation demonstrating how the “number” equates to the schedule provided by the TOP. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit.

Question 6

VAR-002-3, Requirement R4 was added because generators cannot report a capability change until they are aware of the change. The currently enforceable standard requires a notification as soon as the capability change occurs; however, many times the change occurred well before the generators were aware of the problem. Is it clear that VAR-002-3 Requirement R4 is only violated after the generator is made aware of the change?

Compliance Response to Question 6

It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the reactive capability change. An auditor will ask an entity for evidence to demonstrate when it became aware of the change in reactive capability. This will not be purely subjective; there are technical instances where it will be clear that an entity would have been made aware of the change in reactive capability. For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.

VAR Mapping Document

Transition of VAR-001-3 and VAR-002-2b

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R1	Requirement R1	This requirement is duplicated in other standards, and the new requirement has been simplified to require the specification of the voltage and Reactive Power schedules and associated tolerance bands. A new part 1.1 has been added to allow for voltage coordination with adjacent TOPs and applicable RCs.
VAR-001-3 R2	Requirement R2	The new requirement has been updated to scheduling of resources. It eliminates the need for the existing R7, R8, and R9. It also maintains a list of sufficient reactive resources.
VAR-001-3 R3	Requirement R4	The new requirement has been simplified by removing the need to maintain an exemption list. Instead, the standard focuses on whether the exemption criteria are known and whether a granted exemption was communicated to the applicable Generator.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R4	Requirement R5	The new requirements have been updated to allow the TOP to provide the voltage or Reactive Power schedule at either the high side or the low side of the GSU. Also as tolerance band is now required under the new requirement. New parts have also been added to direct a GOP to operate in AVR, to require the TOP to provide notification requirements, and to provide the criteria for developing schedules and tolerance bands upon request.
VAR-001-3 R5	Deleted	Pending a final rulemaking on P81, this requirement has been deleted.
VAR-001-3 R6	Deleted	This requirement is deleted because the TOP standards require knowing the status of Reactive Power resources. Although power system stabilizers are not specifically named in the TOP standards, the areas that rely on PSS equipment will require monitoring the status under the data specifications of the TOP standards.
VAR-001-3 R7	Deleted	This has moved into the new R3.
VAR-001-3 R8	Deleted	This has moved into the new R3.
VAR-001-3 R9	Deleted	See comments for new R2.
VAR-001-3 R10	Deleted	This is duplicative of TOP-001-2 and the Tv definition.
VAR-001-3 R11	Requirement R6	The requirement has been updated to allow for scheduling consultation.
VAR-001-3 R12	Deleted	This requirement was deleted because the EOP standards address taking any corrective action including load-shedding. Also the new TOP-002-3 R2 and TOP-001-2 R11 address the TOP taking corrective actions.

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b R1	Requirement R1	The requirement has been modified to allow for testing and exemptions for other AVR modes when necessary.
VAR-002-2b R2	Requirement R2	The new requirement has been updated to allow for TOP-defined notification requirements. The requirement also adds parts to allow for the conversion of a high side schedule to a low side number for monitoring purposes.
VAR-002-2b R3	Requirement R3 and R4.	The old requirement has been broken into two requirements: 1) one for AVR/PSS status, and 2) one for reactive capability. Both allow 15 minutes to correct an issue before having to notify the TOP.
VAR-002-2b R3	Requirement R4	The requirement has not been modified.
VAR-002-2b R4	Requirement R5	The requirement has not been modified.

VAR Mapping Document

Transition of VAR-001-3 and VAR-002-2b ~~(the *pro forma* standard)~~

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R1	Requirement R1	This requirement is duplicated in other standards,~~The *pro forma* creates adds additional sub-requirements that requires the policies~~ and the new requirement has been simplified~~procedures~~ to require the specification of the~~include criteria for system assessments. The assessments must now include steady-state limits,~~ voltage and Reactive Power schedules ~~stability limits~~ and associated ~~operating margins, and voltage schedules along with associated~~ tolerance bands. A new part 1.1 has been added to allow for voltage coordination with adjacent~~The sub-requirements also now mandate that information is shared with neighboring~~ TOPs and ~~the~~ applicable RCs~~RC~~.
VAR-001-3 R2	Requirement R2	The new requirement has been updated to ~~incorporate real-time and day-ahead~~ scheduling of resources. It eliminates the need for the existing R7, R8, and R9. It also maintains a list of sufficient reactive resources.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
VAR-001-3 R3	Requirement R4~~R3~~	The new requirement has been simplified by removing the need to maintain an exemption list. Instead, the standard focuses on whether the exemption criteria are known and whether a granted exemption was communicated to the applicable Generator.
VAR-001-3 R4	Requirement R5~~R4~~	The new requirements have been updated to allow the TOP to provide the voltage or Reactive Power schedule at either the high side or the low side of the GSU. Also as tolerance band is now required under the new requirement. New parts have also been added to direct a GOP to operate in AVR, to require the TOP to provide notification requirements, and to provide the criteria for developing schedules and tolerance bands upon request.
VAR-001-3 R5	Deleted	Pending a final rulemaking on P81, this requirement has been deleted.
VAR-001-3 R6	Deleted~~Requirement R5~~	This requirement is deleted because the TOP standards require knowing the status of Reactive Power resources. Although power system stabilizers are not specifically named in the TOP standards, the areas that rely on PSS equipment will require monitoring the status under the data specifications of the TOP standards.~~The sub-requirement R6.1 was deleted because it is duplicative of VAR-002's requirement R1 and R2.~~
VAR-001-3 R7	Deleted	This has moved into the~~See comments for~~ new R3~~R2~~.
VAR-001-3 R8	Deleted	This has moved into the~~See comments for~~ new R3~~R2~~.
VAR-001-3 R9	Deleted	See comments for new R2.
VAR-001-3 R10	Deleted	This is duplicative of TOP-001-2 and the Tv definition.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R11	Requirement R6	The requirement has been updated to allow for scheduling consultation.~~The only change is the numbering due to other deletions.~~
VAR-001-3 R12	Deleted	This requirement was deleted because the EOP standards address taking any corrective action including load-shedding. Also the new TOP-002-3 R2 and TOP-001-2 R11 address the TOP taking corrective actions.

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b R1	Requirement R1	The requirement has ~~not~~ been modified to allow for testing and exemptions for other AVR modes when necessary.
VAR-002-2b R2	Requirement R2	The new ~~*pro forma*~~ requirement has been updated to allow for TOP-defined notification requirements. The ~~by including a new sub-~~ requirement also adds parts~~to allowing GOPs~~ to allow for the conversion of a high side schedule to a low side number for monitoring purposes~~only call in certain instances when deviating from voltage schedules~~.
VAR-002-2b R3~~R2~~	Requirement R3 and R4.	The old~~new *pro forma*~~ requirement has been broken into two requirements: 1) one for AVR/PSS ~~updated by including a new sub-requirement to allowing GOPs to investigate why the~~ status, and 2) one for reactive capability. Both allow 15 minutes to correct an issue ~~has changed on AVR equipment~~ before having to notify the TOP.

Standard: VAR-002-3 – Capacity Benefit Margin		
Requirement in Approved Standard	Transitions to the below Requirement in New Standard or Other Action	Description and Change Justification
VAR-002-2b R3~~R2~~	Requirement R4	The requirement has not been modified.
VAR-002-2b R4~~R2~~	Requirement R5	The requirement has not been modified.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

VAR-001-4 – Voltage and Reactive Control

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X		
R2													X		
R3													X		
R4													X		
R5													X		
R6													X		

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

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.

1.1. Each Transmission Operator shall provide a copy of the voltage schedules and associated tolerance bands 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 were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[3]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M1.
Documentation of request made per Part 1.1 from Reliability Coordinator and/or adjacent Transmission Operators, if applicable and requested by auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

[3] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R1
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Review evidence provided and ensure it meets the requirements outlined in Requirement R1.
	(Part 1.1) Examine evidence to verify that voltage schedules were provided within 30 days of request per Part 1.1.

Note to Auditor: Auditors, at their discretion and based on the risk of the entity's compliance with this requirement to the BES, may communicate with Balancing Authorities and other Transmission Operators to determine if data requests were made of the entity. Auditors may also accept entity assertions regarding whether data requests made.

Entity assertions that no data requests were made do not have to be in writing.

Auditor Notes:

R2 Supporting Evidence and Documentation

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.

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

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review the studies/assessments that entity used to schedule resources to determine that the studies show whether new resources should be brought online, or if the resources online are sufficient to regulate voltage levels. Auditors should verify that actual scheduling reflected the results of the studies/assessments.

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough instances, per above, to gain reasonable assurance that entity is complying with Requirement R2.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary.

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity operates or directs devices to regulate transmission voltage and reactive flow as necessary, if the entity has such documents.
Evidence as outlined in M3 as requested by auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

where evidence of compliance may be found.

Audit Team Evidence Reviewed **(This section to be completed by the Compliance Enforcement Authority)**:

Compliance Assessment Approach Specific to VAR-001-4, R3

This section to be completed by the Compliance Enforcement Authority

	Review evidence to understand how entity operates or directs devices to regulate transmission voltage and reactive flow as necessary. Auditors may sample system events or other instances of voltage irregularities to verify that operations or directions occurred as required per Requirement R2.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough events or other instances of voltage irregularities, per above, to gain reasonable assurance that entity is complying with Requirement R2.

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. The Transmission Operator shall specify the criteria that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements.

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 generating unit in its area that is exempt from: 1) 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.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[6]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review evidence and note existence of exemption criteria per Requirement R4. For a sample of exempted generators, verify that exemption was granted in accordance with criteria.

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	(Part 1.1) For a sample of exempted generators, ensure exempted generator was notified.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough generators, per above, to gain reasonable assurance that entity is complying with Requirement R4.

Requirement R4 allows for any combination of exemptions for generator operators from 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements, as long as the exemption meets the criteria specified by the entity. An auditor will not look for any pre-authorization from the entity; rather an auditor will verify that the generator operator has met the criteria set forth by the entity.

Auditor Notes:

R5 Supporting Evidence and Documentation

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.

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (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.

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules and associated tolerance bands 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 and tolerance band.

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule and 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. The evidence shall include written records, email, or voice recordings.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule and associated tolerance band. The evidence shall include written records, email, or voice recordings.

For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules and associated tolerance bands within 30 days of receiving a request by a Generator Operator.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M5.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R5
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Verify existence of voltage or Reactive Power schedule and that it meets the requirements of Requirement R5.
	(Part 5.1) For a sample of Generator Operators, verify voltage or Reactive Power schedule was provided

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	per Part 5.1.
	(Part 5.2) For a sample of Generator Operators, verify the notification requirements for deviations from the voltage or Reactive Power schedule was provided per Part 5.2.
	(Part 5.3) For a sample of Generator Operators, verify criteria was provided as requested per Part 5.3.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough notifications, per above, to gain reasonable assurance that entity is complying with Requirement R5.

It is clear based on VAR-001-4 Requirement R5 that a voltage or Reactive power schedule can be either: 1) a target number with a tolerance band, Or 2) a voltage or Reactive Power range to operate within. An auditor would not expect to see a tolerance band provided with an operating range for voltage or Reactive Power.

Auditor Notes:

<u>**R6 Supporting Evidence and Documentation**</u>

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.

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.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

See M6.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R6

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Understand entity's procedures concerning coordinating tap settings with Generator Owners per Requirement R6.
	For a sample of Generator Owners, verify tap setting changes were executed per Requirement R6.
Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough tap setting communications, per above, to gain reasonable assurance that entity is complying with Requirement R6.	

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/07/2013	NERC compliance, Standards	New Document

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1				X											
R2				X											
R3				X											
R4				X											
R5			X												
R6			X												

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

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) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has notified the Transmission Operator of one of the following:

- That the generator is being operated in start-up,[3] shutdown,[4] 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 the automatic voltage control mode 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 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. Such evidence must 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 exempted, the Generator Operator shall also have evidence that it is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

Registered Entity Response to Question (Required):

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

[3] 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.
[4] 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.
[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

See M1.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	For instances where entity did not operate a generator in automatic voltage control mode, ensure notification was given to the Transmission Operator in accordance with Requirement R1.
Note to Auditor: Auditors can identify instances where entities operated generators outside of automatic voltage control mode through their general knowledge of the interconnected transmission system in the entity's area. Auditor knowledge is obtained through activities such as conversations with the entity under audit or the Transmission Operator, and an awareness of events occurring on the interconnected transmission system. In situations where the entity's compliance with this requirement poses little risk to the BES, conversations with other entities, such as Transmission Operators, is most likely not necessary.	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[6] (within each generating Facility's capabilities[7]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage schedule provided by the Transmission Operator.

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 directed by the Transmission Operator.

2.2. When directed 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 unit 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 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 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 directed by the Transmission Operator.

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

For part 2.3, for units that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.

Question: As a Generation Operator, have you operated the generator with the AVR out of service?

[6] 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.

[7] 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.

Registered Entity Response to Question (Required):

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.
Any written policies, procedures or protocols describing how the entity maintains the generator voltage or Reactive Power schedule provided by Transmission Operator, if the entity has such documents.
Generator voltage or Reactive Power schedule provided to entity by Transmission Operator, or entity's record thereof, for timeframes selected by the auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R2
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	Interview entity staff and/or review documentation provided by the entity to understand how they maintain the generator voltage or Reactive Power schedule or authorized exemption per Requirement R2.
	Read entity's response to compliance Question above and understand how entity complies with Requirement R2, when they operate a generator with AVR in not in service.
	Select a sample of timeframes during the audit period and have entity walkthrough how they complied with Requirement R2 for those timeframes.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough timeframes, per above, to gain reasonable assurance that entity is complying with Requirement R2.

For part 2.3, the entity should be able to provide documentation that identifies the voltage number being monitored and the calculation demonstrating how it equates to the schedule provided by the Transmission Operator. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit. The entity can only be responsible for maintaining the schedule provided by the Transmission Operator based on existing facility equipment. In the event that an entity does not have the equipment to have visibility of high-side system voltage, the entity will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the entity does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the entity is non-compliant. However, if the Transmission Operator provides a new directive or schedule, the entity is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the entity is expected to comply pursuant to VAR-002-3.

Auditor Notes:

R3 Supporting Evidence and Documentation

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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator.

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3. If the status has been restored within the first 15 minutes, no notification is necessary; therefore, if a status change lasts more than 15 minutes, the GOP must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[9]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity responds to a status change on AVR, if the entity has such documents. An example of entity's response to a status change on AVR provided by entity, if applicable.
Auditor may select certain instances where entity had a status change on AVR. In such instances, provide associated evidence of awareness and resolution/notification.
Evidence as outlined in M3.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R3
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they

[9] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	respond to status changes on AVR.
	Review evidence provided to determine if entity responded to status change on AVR in accordance with Requirement R3.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough timeframes, per above, to gain reasonable assurance that entity is complying with Requirement R3.

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes after 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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of the recognition of a reactive capability change identified in Requirement R4. If the capability has been restored within the first 15 minutes, no notification is necessary; therefore, if a capability change lasts more than 15 minutes, the Generator Operator must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[10]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means

[10] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity responds to a change in reactive capability, if the entity has such documents. An example of entity's response to a change in reactive capability provided by entity, if applicable.
Auditor may select certain instances where entity should have been aware of a status change in reactive capability. In such instances, provide associated evidence of awareness and resolution/notification. See Note to Auditor for additional details.
Evidence as outlined in M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R4

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they respond to change in reactive capability.
	Review evidence provided to determine if entity responded to change in reactive capability in accordance with Requirement R4.

Note to Auditor: It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the status change in reactive capability. An auditor will ask an entity for evidence to demonstrate when it became aware of the change. This will not be purely subjective; there are technical instances (e.g. unit trips, ramping, equipment/AVR failures) where it will be clear that an entity would have been made aware of the change in reactive capability. For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.

Auditor Notes:

<u>R5 Supporting Evidence and Documentation</u>

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

5.1. For generator step-up transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirements R5 part 5.1.1 through part 5.1.3.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[11]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M4. Evidence of transmittal of the data could include, but is not limited to, items such as an electronic message or a transmittal letter with the information included or attached.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[11] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to VAR-002-3, R5
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and reply) to determine if entity responded to information request(s) as required in Requirement R5 within 30 days of receiving a request from associated Transmission Operator.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Transmission Operators to determine if requests for data were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

R6 Supporting Evidence and Documentation

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.

6.1. If the Generator Operator cannot comply with the Transmission Operator's specifications, the Generator Operator 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 as identified in Requirement R6. The Generator Operator 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 as identified in Requirement R6 part 6.1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[12]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M6.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R6
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and response) to determine if entity responded to change(s) as required in Requirement R6.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Transmission Operators to determine if requests for changes to transformer tap positions were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

<u>Revision History</u>

Version	Date	Reviewers	Revision Description
1	11/XX/2013	NERC compliance,	New Document

[12] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

		Standards	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control VAR-001-4 & VAR-002-3

Comment Period: October 11, 2013 – November 25, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: November 15, 2013 – November 25, 2013

Now Available

A 45-day formal comment period for **VAR-001-4 and VAR-002-3** is open through **8 p.m. Eastern on Monday, November 25, 2013.**

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

Instructions for Commenting
A formal comment period is open through **8 p.m. Eastern on Monday, November 25, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined. During the initial comment period, two ballot pools were formed (one to ballot the standards and one for the non-binding polls). For this ballot and non-binding poll, each standard and its associated non-binding poll will be balloted separately (for a total of two standard ballots and two non-binding polls). The original ballot pools will be used for the individual standard ballots and non-binding polls.

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

For more information or assistance, please contact Arielle Cunningham, Standards Development Administrator, at Arielle.Cunningham@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement Reminder

Project 2013-04 Voltage and Reactive Control
VAR-001-4 and VAR-002-3

Additional Ballots and Non-Binding Polls now open through November 25, 2013

Now Available

Additional ballots for **VAR-001-4 and VAR-002-3** and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Monday, November 25, 2013.**

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

Instructions for Commenting

Members of the ballot pools associated with this project may log in and submit their vote for the standards and non-binding polls of the associated VRFs and VSLs by clicking here.

Next Steps

The ballot results for **VAR-001-4 and VAR-002-3** will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments do not show the need for significant revisions, the standards will proceed to final ballots.

Standards Development Process

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

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-001-4 & VAR-002-3

Comment Period: October 11, 2013 – November 25, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: November 15, 2013 – November 25, 2013

Now Available

A 45-day formal comment period for **VAR-001-4 and VAR-002-3** is open through **8 p.m. Eastern on Monday, November 25, 2013.**

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

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Monday, November 25, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

Additional ballots for the standards and non-binding polls of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined. During the initial comment period, two ballot pools were formed (one to ballot the standards and one for the non-binding polls). For this ballot and non-binding poll, each standard and its associated non-binding poll will be balloted separately (for a total of two standard ballots and two non-binding polls). The original ballot pools will be used for the individual standard ballots and non-binding polls.

Standards Development Process

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

For more information or assistance, please contact Arielle Cunningham,
Standards Development Administrator, at Arielle.Cunningham@nerc.net or at 404-446-2560.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-001-4 and VAR-002-3

Additional Ballot and Non-Binding Poll Results

Now Available

Additional ballots for **VAR-001-4 and VAR-002-3** and non-binding polls of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, November 26, 2013.**

VAR-001-4 received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

	Ballot	Non-Binding Poll
	Quorum /Approval	Quorum/Supportive Opinions
VAR-001-4	80.81% / 69.43%	78.73% / 57.75%
VAR-002-3	81.06% / 66.09%	79.01% / 57.87%

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

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standards. If the comments show the need for significant revisions, the standards will proceed to an additional comment and ballot period. If the comments do not show the need for significant revisions, the standards will proceed to a final ballot.

Standards Development Process

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

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Admin Home
Registered Ballot Body
Ballot Events
Current Ballot Pools
Current Ballots
Previous Ballots
Vetting
Proxy Pool
NERC Home

Ballot Results

Ballot Name:	Project 2013-04 Voltage and Reactive Control VAR-001-4 Additional Ballot
Ballot Period:	11/15/2013 - 11/26/2013
Ballot Type:	Additional Ballot
Total # Votes:	320
Total Ballot Pool:	396
Quorum:	**80.81 % The Quorum has been reached**
Weighted Segment Vote:	69.43 %
Ballot Results:	**The Ballot has passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	106	1	49	0.636	28	0.364	0	8	21
2 - Segment 2	9	0.9	7	0.7	2	0.2	0	0	0
3 - Segment 3	86	1	41	0.641	23	0.359	0	7	15
4 - Segment 4	30	1	14	0.737	5	0.263	0	7	4
5 - Segment 5	98	1	37	0.587	26	0.413	1	11	23
6 - Segment 6	52	1	23	0.59	16	0.41	0	3	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.6	5	0.5	1	0.1	0	2	0
Totals	**396**	**6.9**	**180**	**4.791**	**101**	**2.109**	**1**	**38**	**76**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	

1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC Comments)
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
				SUPPORTS THIRD PARTY

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	COMMENTS - (Public Service Enterprise Group)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (North American Generator Forum)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	

3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (- Florida Municipal Power Agency comments)
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	

3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supporting Southwest Power Pool comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED - (North American Generator Forum)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
				COMMENT

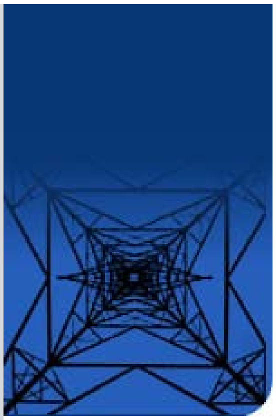
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy's)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Brett Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Ameren comments)
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Commnets

				submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	NO COMMENT RECEIVED - (SERC OC)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lafayette Utilities System	Jamie B Webb	Affirmative	
				SUPPORTS THIRD PARTY COMMENTS -

5	Lakeland Electric	James M Howard	Negative	(Florida Municipal Power Association)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Compliance Grp)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Bonnie Marino-Blair	Negative	COMMENT RECEIVED
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	COMMENT RECEIVED - (North American Generator Forum)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith on behalf of Seminole Electric Cooperative

				Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (mro nsrf)
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Negative	COMMENT RECEIVED
5	Vandolah Power Company L.L.C.	Douglas A. Jensen	Abstain	
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (support the SPP Standards Group's comments)
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	

6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	COMMENT RECEIVED - (North American Generator Forum)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	



9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2013-04 Voltage and Reactive Control VAR-002-3 Additional Ballot
Ballot Period:	11/15/2013 - 11/26/2013
Ballot Type:	Additional Ballot
Total # Votes:	321
Total Ballot Pool:	396
Quorum:	**81.06 % The Quorum has been reached**
Weighted Segment Vote:	66.09 %
Ballot Results:	**The Ballot has closed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	106	1	44	0.611	28	0.389	0	13	21
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	0	1
3 - Segment 3	86	1	41	0.641	23	0.359	0	7	15
4 - Segment 4	30	1	16	0.727	6	0.273	0	4	4
5 - Segment 5	98	1	36	0.537	31	0.463	1	8	22
6 - Segment 6	52	1	21	0.512	20	0.488	0	2	9
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.2	2	0.2	0	0	0	0	2
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.5	4	0.4	1	0.1	0	3	0
Totals	**396**	**6.7**	**172**	**4.428**	**111**	**2.272**	**1**	**37**	**75**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRo NSRF)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRG)
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by PGE Angela Gaines.)
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	

1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (North American Generator Forum)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		

3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (- Florida Municipal Power Agency comments)
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)

3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supporting Southwest Power Pool comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED - (North American Generator Forum)
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	

3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Brett Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
				SUPPORTS

5	Amerenue	Sam Dwyer	Negative	THIRD PARTY COMMENTS - (see Ameren's comments)
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	NO COMMENT RECEIVED - (SERC OC)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(NSRF)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lafayette Utilities System	Jamie B Webb	Affirmative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municpal Power Association)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Compliance Grp)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Negative	COMMENT RECEIVED
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
				COMMENT

5	Santee Cooper	Lewis P Pierce	Negative	RECEIVED - (North American Generator Forum)
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith on behalf of Seminole Electric Cooperative Inc)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Negative	COMMENT RECEIVED
5	Vandolah Power Company L.L.C.	Douglas A. Jensen	Abstain	
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (support the SPP Standards Group's comments)
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Negative)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Exelon Companies)
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	

6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Generation Company LLC)
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (North American Generator Forum)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		

6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-Binding Poll Results

Project 2013-04 Voltage and Reactive Control (VAR)
VAR-001-4

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2013-04 VRC VAR-001-4 Non-binding Poll
Poll Period:	11/15/2013 - 11/26/2013
Total # Opinions:	285
Total Ballot Pool:	362
Summary Results:	78.73% of those who registered to participate provided an opinion or an abstention; 57.75% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida

				Municipal Power Agency)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		

1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)

1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (North American Generator Forum)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT

				RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (- Florida Municipal Power Agency comments)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supporting Southwest Power Pool comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED - (North American Generator Forum)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Brett

				Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT

				RECEIVED
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	NO COMMENT RECEIVED - (SERC OC)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		

5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Compliance Grp)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Bonnie Marino-Blair	Negative	COMMENT RECEIVED
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	COMMENT RECEIVED - (North American Generator Forum)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret

				Galbraith on behalf of Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (mro nsrf)
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Negative	COMMENT RECEIVED
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke energy)
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS

				THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	COMMENT RECEIVED - (North American Generator Forum)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret

				Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyde Linke)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Non-Binding Poll Results

Project 2013-04 Voltage and Reactive Control (VAR) VAR-002-3

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2013-04 VRC VAR-002-3 Non-binding Poll
Poll Period:	11/15/2013 - 11/26/2013
Total # Opinions:	286
Total Ballot Pool:	362
Summary Results:	79.01% of those who registered to participate provided an opinion or an abstention; 57.87% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson		
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		

NERC

1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Abstain	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by PGE Angela Gaines.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	

NERC

1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	SUPPORTS THIRD PARTY COMMENTS - (North American Generator Forum)
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	

3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo		
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Tallahassee	Bill R Fowler	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	SUPPORTS THIRD PARTY COMMENTS - (- Florida Municipal Power Agency comments)
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	

NERC

3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Supporting Southwest Power Pool comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED - (North American Generator Forum)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	

3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative (Bret Galbraith))
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD

				PARTY COMMENTS - (Thomas Foltz - American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Negative	NO COMMENT RECEIVED - (SERC OC)
5	El Paso Electric Company	Gustavo Estrada		

5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	COMMENT RECEIVED
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Compliance Grp)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Negative	COMMENT RECEIVED

5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	COMMENT RECEIVED - (North American Generator Forum)
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret gailbraith on behalf of Seminole Electric Cooperative Inc.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Negative	COMMENT RECEIVED
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas		
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	

6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Negative	COMMENT RECEIVED - (North American Generator Forum)
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith will be submitting comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (59 Responses)
Name (39 Responses)
Organization (39 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (12 Responses)
Comments (59 Responses)
Question 1 (34 Responses)
Question 1 Comments (47 Responses)
Question 2 (43 Responses)
Question 2 Comments (47 Responses)
Question 3 (0 Responses)
Question 3 Comments (47 Responses)
Question 3 (0 Responses)
Question 3 Comments (47 Responses)

Group
MRO NSRF
Russel Mountjoy
Yes
In requirement 5.1 a Transmission Operator is required direct a Generator Operator to “comply with the schedule” provided by the Transmission Operator. In 5.2, however, the potential for deviations from the schedule is implied. To avoid conflict between these two, the following change to 5.1 is recommended: “The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode unless notification of deviation is provided in accordance with 5.2.” For consistency M2 should be reworded as follows: “For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled” The current wording of “shall provide copies” imposes an action that is not included in the associated requirement. In previous comments regarding voltage schedules issued by a Transmission Operator a mechanism for a Generator Operator to provide explanations if a proposed schedule could not reasonably be met based on specific equipment limitations and to get a revised schedule or exemption was suggested. In this version the Transmission Operator is obligated to provide additional information about the schedule, but is not obligated to respond to Generator Operator concerns regarding the schedule. Under VAR-002 a Generator Operator is required to comply with the schedule provide by the Transmission Operator unless notification is provided. There then is the potential situation where a schedule issued by a Transmission Operator cannot be met due to equipment or system conditions and the only action available is for a Generator Operator to provide multiple notifications. A better solution it seems would be to include some sort of feedback process

between Generator Operators and Transmission Operations in the VAR-001 standard that would result in an agreed-upon schedule that could reasonably be met without burdensome periodic notifications. As recommended in previous comments a process of reaching “mutual agreement” on the schedule for making transformer tap changes is suggested . The SDT responded in the consideration of comments that they did not chose to include the suggested agreement language but did add a requirement for the transmission operator to provide an “implementation schedule”. While this change is an improvement it does not completely solve the concern presented. The objective should be that a tap change schedule is agreed upon that would meet the reasonable needs of both the Transmission Operator and Generator Operator. The following from requirement R2: “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” implies that all of the items listed need to be considered. If the intent is that the items are intended to be examples it is suggested that the words “including , but not limited to” be replaced by “such as”. It is recommended that R5.1 be modified as recommended by the NERC IGVT report of September 2012: 5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR or plant-level volt/var regulator is in service and controlling voltage). The standard should be reviewed and where AVR is referred to, the plant-level volt/var regulator should be added in a similar way to this recommended change to R5.1. The referenced NERC report provides the technical basis for this recommendation.
The revised VAR-002 R2.1 removes the 15 minute deviation criteria for notification by Generator Operators to Transmission Operators. The revised VAR-001-4 requires Transmission Operators to provide notification requirements. The drafting team in the consideration of comments explained “In an effort to remove prescriptive notification requirements for the entire continent” the change was made. This leaves the Generator Operators at the mercy of Transmission Operators who could potentially set a no deviation criteria. It is recommended that a compromise be struck by specifying a limit on the criteria such as “no less than 15 minutes”. For clarification it is recommended that the word “generator” be added before the word “stability” in the last sentence of footnote 6. [Note to NSRF: a comment on this was submitted previously but it did not have a recommended language change] In M2 it is recommended that “alarm logs” be added to the list of evidence. We support the deletion of the language regarding notification of the expected duration of a change in status. At the time a status change occurs it is often difficult to provide a meaningful estimate of the duration of the change. Requirement 3 should be revised to state – Notification must be made within 30 minutes of becoming aware of the change from automatic controlling voltage for the AVR, and from in-service of the PSS. Measure 3 should be revised to reflect this as well. The following change to requirement R4 is recommended: “Reactive capability changes due to factors such as a change in the wind speed for wind generators or a change in the solar resource for solar facilities do not require Transmission Operator notification” Measure 4 should be revised to reflect the wording in Requirement 4 – Notification must be made within 30 minutes of becoming aware of the change of state of the AVR. For the same reason

described above for VAR-001 (NERC IGVT Report), R1 should be modified as follows: “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) or plant-level volt/var regulator in service and controlling voltage) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has notified the Transmission Operator of one of the following:” A similar addition should be made where the AVR is referred to in the other requirements of VAR-002.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
We support the direction being taken and the SDT’s decision to not reiterate or duplicate the voltage assessment requirements already addressed by the FAC and TOP standards.
Yes
We support the SDT’s proposal to remove the requirements that may be redundant with other standards. However, regarding VAR-001-4 Requirement R1 was revised to read: 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 1.1 Each Transmission Operator shall provide a copy of the voltage schedules and asspociated tolerance bands to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. What is meant by “system voltage schedule.” Is it a high-level, overall voltage schedule by voltage class, or a voltage schedule by station (even if there is no direct means of controlling voltage at that station)? Requirement R5 already addresses specification of generator voltage schedules, so if that is what is intended to be addressed under R1, why is R1 needed at all? Requirement R5 states: 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. There is inconsistency in the tense used in various VSLs. Some are in present tense while others are in the past tense. This should be reviewed and and revised as appropriate. “Schedule” is used in both VAR-001 Requirements R1 and R5. However, it is modified by different phrases in each, implying different types of “schedules.” These two different types of “schedules” have caused confusion, making the use and intended meaning less than perfectly clear. VAR-001 Requirement R1 - To improve clarity and consistency, suggest that the word “schedule” be deleted here and only be used when referring to GOP operation. Suggest revising Requirement R1 wording as follows: R1. Each Transmission Operator shall specify a system voltage 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. Note that Requirement R1 only requires that the TOP establish the target system voltage level and tolerance band. There is no mention of GOP operation. Requirement R2 requires that the TOP schedule its arrangement of sufficient reactive resources, whether actually used (dispatched)

or not, a Planning function (see Measure M2). The Rationale box states: “to ensuring sufficient reactive resources are online or scheduled.” The use of the word “scheduled” here again has caused confusion. We suggest it be replaced to clarify the meaning, as follows: R2. Each Transmission Operator shall make arrangements for sufficient on-line, available 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, making arrangements for reactive generation resources, transmission line and reactive resource switching, and using controllable load. Further recommend revising M2 to synchronize it with the revised Requirement R2 above, as follows: M2. Each Transmission Operator shall have evidence of sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall provide copies of assessments used as the basis for determining how resources were made available. Organizationally, R4 should be swapped with R5. A requirement dealing with exemptions should come after the “foundation” requirement. The Drafting Team must consider the following regarding Hydro-Quebec TransEnergie. "Schedule" in the standard is confusing and does not apply to Hydro-Québec TransÉnergie. Hydro-Quebec TransEnergie does not issue a schedule of voltage or reactive power. Hydro-Quebec TransEnergie sets voltage ranges to comply at all times for the different voltage levels. During light or peak load, these operating situations are governed with voltage setupoints for specific substations. The standard should therefore consider (in addition to the preceding comments) the terms used. For example, consider substituting the term " voltage or reactive power setpoint " for the word “schedule” which does not reflect our operating procedures. Regarding Requirement R5, NERC now requires a specified program voltage or reactive power be given to central planning and forecasting. This requirement is not applicable to Hydro-Québec TransÉnergie because there is no voltage or reactive power schedule, but rather the requirement that every generating facility of more than 10 MW have an automatic voltage regulation system. Hydro-Quebec TransEnergie also requires them to provide a specific power factor for each of those generating units.
Suggest the following changes to more effectively convey the intents of Measure M3 and Requirement R6. Suggest that Measure M3 be reworded to require demonstration of compliance rather than to require actions which should have been stipulated in the requirement. Specifically, we proposed the last part in Measure M3 be revised to: “…therefore, if a status change lasts more than 15 minutes, the GOP shall provide evidence such as system log, electronic message or a transmittal letter that it notified its associated Transmission Operator within 30 minutes of when the change first occurred.” Regarding R6, the wording “the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator…” is not a direct action and may not be measurable. Suggest revising it to read: “the Generator Owner shall implement the transformer tap positions according to the specifications provided by the Transmission Operator….” We further propose that the SDT insert the evidence language into the first sentence of Measure M3 which asks for evidence that the Generator notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3. Generators may be asked by their TOP to operate in other modes. Reword Requirement

R1 as follows: 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) unless the Generator Operator 1) is exempted by the Transmission Operator, 2) is notified by the Transmission Operator to operate in a different viable operating mode (e.g., constant VAR output mode), or 3) has notified the Transmission Operator of one of the following:… The comments in Question 2 regarding Hydro-Quebec regarding the word "schedule" apply.
We support the proposed VRFs and VSLs.
Individual
aaa
bbb
Agree
Group
Bureau of Reclamation
Erika Doot
Yes
Yes
The Bureau of Reclamation (Reclamation) notes that the WECC variance indicates that it is intended to replace requirements R3 and R4. However, R3 and R4 in VAR-001-4 are not the same as R3 and R4 in VAR-001-3. Reclamation suggests that the drafting team should examine the WECC variance to determine which requirements it will replace because it appears that the WECC variance should replace R4 and R5. In WECC, it would be difficult for Transmission Operators to comply with both R5 and E.A. 14 because they refer to different voltage schedule reference points. VAR-001-4 R3 specifies that Transmission Operators must operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. Measure M3 specifies that “this may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.” Reclamation suggests that this detail should be included in Requirement R3 rather than solely in the measure. VAR-001-4 R4 requires a Transmission Operator to notify a Generator Operator if the “Transmission Operator determines that a generator has satisfied exemption criteria” but does not specify a timeframe for this notification. Reclamation suggests that the drafting team update VAR-001-4 R4 to specify that the Transmission Operator must notify the Generator Operator within 30 days if the Transmission Operator determines that a generator has satisfied criteria for exemption from voltage or Reactive Power requirements and associated notification requirements. Reclamation also suggests that R4 on exemptions should follow R5 on voltage or Reactive Power scheduling and notification criteria. VAR-001 R5 allows the Transmission Operator to specify a voltage or Reactive Power schedule at either the high voltage side or low voltage side of the Generator Step Up transformer. Reclamation suggests that like in requirement E.A.14, Transmission Operators should be able to specify the voltage schedule at the generator terminals, high side of the generator step-up transformer, point of interconnection, or a location designated by mutual

agreement. VAR-001 R5.2 specifies that “The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule.” M5 regarding part 5.2 specifies that voice recordings may be used to establish compliance with this requirement. Reclamation suggests that voice recordings should be removed from the list in M5 for part 5.2 because notification requirements established in the planning horizon should be transmitted in writing. Reclamation notes that there is a potential inconsistency between the Transmission Operator notification requirements discussed in VAR-001 R5.2 and the Generator Operator notification requirements discussed VAR-002 R3 and R4. Reclamation recommends that VAR-001 R5.2 be modified to solely address planning horizon notifications. For consistency with the Generator Operator real-time notification requirements established in VAR-002 R3 and R4, Reclamation also recommends that VAR-001-4 R5 should include an additional subrequirement which specifies that the “TOP shall develop real-time notification requirements for the deviations from the voltage of Reactive Power schedule within 30 minutes of when a Generator Operator becomes aware of a change in reactive capability, AVR status, power system stabilizer status, or alternative voltage controlling device status, unless the status is restored within 15 minutes.” VAR-001-4 R5 requires the Transmission Operator to specify a voltage or Reactive Power schedule “at either the high voltage side or low voltage side of the Generator Step-Up transformer.” VAR-002-3 R2.3 allows Generator Operators to monitor voltages at another location so long as the Generator Operator has a “methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.” Reclamation suggests that having the Transmission Operator and Generator Operator monitor voltages at different locations could lead to confusion in real-time communications. Reclamation suggests that VAR-001-4 R5 be updated to require the Transmission Operator to set voltages based on common monitoring locations to avoid confusion in real-time communications between Transmission Operators and Generator Operators. Reclamation suggests that R6 should be updated to specify that the Transmission Operator must coordinate outages to accommodate required step-up transformer tap changes. Reclamation suggests the drafting team update the requirement to read “After consultation with the Generator Owner regarding necessary step-up transformer tap changes, associated outages, and the implementation schedule…”. Reclamation also notes that "Generator Step-Up transformer" is sometimes capitalized in the standard. However, it is not capitalized in the WECC variance or NERC Glossary. Reclamation suggests that the drafting team remove capitalization in the term “Generator Step-Up transformer” because it is not defined in the NERC Glossary.
Reclamation believes that the notification requirements in R2 and R3 should provide the continent-wide standard. Reclamation suggests that the bullet points in R1 should be relabeled as sub-requirements R1.1 and R1.2. Reclamation requests that the drafting team clarify the timeframe for notifications required by R1. Reclamation suggests that the drafting team update VAR-002-3 R2 to allow Generator Operators to notify Transmission Operators that a voltage schedule cannot be met for equipment or other reasons, so that the Transmission Operator can alter the voltage schedule accordingly. R2.2 recognizes that a Generator Operator can provide an explanation that a voltage schedule cannot be met “when

directed to modify voltage" but does not address the planning horizon. Reclamation appreciates that R2 recognizes that generators only need to comply with voltage schedules within facility capabilities, and that footnote 6 recognizes that generating facility capability may not be sufficient at times to pull the system voltage within scheduled tolerance bands. Nevertheless, Reclamation believes that R2 subrequirements should more clearly articulate that (1) Generator Operators should provide Transmission Operators with feedback that they cannot meet voltage schedules in the planning horizon, and (2) generators may not always be capable of modifying system voltage. Reclamation notes that R2.3 applies to real-time operations, and suggests that R2.3 should be updated to require Generator Operators and Transmission Operators to monitor voltage at mutually-agreed upon locations to avoid confusion in real-time communications. Reclamation suggests that the drafting team update VAR-002-3 R3 to specify that the "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 becoming aware of the change." Reclamation also suggests that M3 should be updated to specify that the GOP must notify its associated Transmission Operator "within 30 minutes of becoming aware of the change" rather than "within 30 minutes of when the change first occurred." Reclamation notes that VAR-002-3 R4 specifies that the "Generator Operator shall notify its associated Transmission Operator within 30 minutes after becoming aware of a change in reactive capability… ." Reclamation suggests that M4 should be updated to match this language and specify that the GOP must notify its associated Transmission Operator "within 30 minutes of becoming aware of the change" rather than "within 30 minutes of when the change first occurred." Reclamation requests clarification on types of "changes in reactive capability" that could trigger the notification requirement in R4. Reclamation notes that the time horizon for VAR-002-3 R6 should probably be changed from "Real-Time Operations" to "Operations Planning" to match VAR-001-4 R6 and reflect that tap setting changes are agreed upon in advance rather than in real-time. Reclamation suggests that VAR-002-3 R6 should be updated to match VAR-001-4 R6 and to specify that the Transmission Operator must coordinate outages to accommodate required step-up transformer tap changes. Reclamation suggests the drafting team update the requirement to read "After consultation with the Generator Owner regarding necessary step-up transformer tap changes, associated outages, and the implementation schedule…".
Reclamation suggests that the VSLs for VAR-002-3 R3 and R4 should reflect a range of noncompliance like in VAR-002-2. A failure to notify the Transmission Operator of an AVR, power system stabilizer, or reactive capability change for 35 minutes should not be treated the same as a failure to notify the Transmission Operator of the status change for 75 minutes.
Individual
John Canavan
NorthWestern Energy
Yes
For R2, M2 - It would be very helpful if "their assessments of the system" be clearly defined. For example, would TPL studies suffice as evidence for meeting this requirement or is this more of a real time requirement and if so, what types of evidence is NERC lokking for.

Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Yes
The drafting team used the word “schedule” in both VAR-001 Requirements R1 and R5. However, it is modified by different phrases in each, implying different types of “schedules.” These two different types of “schedules” has caused confusion, making the use and intended meaning less than perfectly clear. VAR-001 Requirement R1 - To improve clarity and consistency, we recommend that the word “schedule” be deleted here and only be used when referring to GOP operation. The revised Requirement R1 wording recommended follows: R1. Each Transmission Operator shall specify a system voltage [delete: 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. Note that Requirement R1 only requires that the TOP establish the target system voltage level and tolerance band. There is no mention of GOP operation. Requirement R2 requires that the TOP document its arrangement of sufficient reactive resources, whether actually used (dispatched) or not, a Planning function (see Measure M2). The Rationale box states: “to ensuring sufficient reactive resources are online or scheduled.” Comment: The use of the word “scheduled” here again has caused confusion. We recommend it be replaced to clarify the meaning, as follows: R2. Each Transmission Operator shall make arrangement for [delete: schedule] sufficient on-line, available 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, making arrangements for reactive generation resources [delete: scheduling], transmission line and reactive resource switching, and using controllable load. We further recommend revising M2 to synchronize it with the revised Requirement R2 above, as follows: M2. Each Transmission Operator shall have evidence of [delete: scheduling]sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall provide copies of assessments used as the basis for determining how resources were [delete: scheduled] made available. The verbiage of R4 should come after R5 is stated. From an organizational perspective, a requirement paragraph on exemptions should come after the referenced requirement.
Generators may be asked by their TOP to operate in other modes. Reword Requirement R1 as follows: 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) unless the Generator Operator 1) is exempted by the Transmission Operator, [delete: or] 2) is notified by the Transmission Operator to operate in a different viable operating mode (e.g., constant VAR output mode), or 3) has notified the Transmission Operator of one of the following:
Individual
Ronnie C. Hoeinghaus
City of Garland

Yes
1st question: Yes - we agree with this approach 2nd question: We have comments on R2. In ERCOT, the TOP can only plan to respond to voltage issues with the resources they have available. They do not have authority to order generation on line for voltage support nor do they have authority to back down fully loaded generation for voltage support. Only the RC has this authority.
Individual
Thomas Foltz
American Electric Power
No
R5: Rather than allowing only 30 days, we instead recommend that the Generator Owner be allowed to provide the data within the timeframe agreed upon by the GO and either the Transmission Operator or Transmission Planner. This data is often part of larger data submission that may stretch beyond the proposed time horizon. In addition, providing this data to the TP appears to be duplicative of the MOD standards currently being updated. As a result, we recommend removing the TP from this requirement. R6: We recommend that Requirement 6 and its subrequirement be applicable only to the Generator Owner and not split between the Generator Owner and Generator Operator. If both are to be retained, we recommend that the subrequirement be changed to state “*If* the Generator Owner cannot provide tap setting changes as requested, the Generator Owner or Generator Operator should notify the Transmission Operator…”
R3 & R4 do not require communications for all instances. As a result, the severe VSL text must be qualified so that it only applies to those situations where notification is actually necessary.
Individual
Oliver Burke
Entergy Services, Inc.
Agree
SERC OC Review Group
Individual
John Seelke
Public Service Enterprise Group
No
1. R4 and part 4.1 address generator exemptions. R4 requires TOPs to develop criteria for exempting generators from R5, part 5.1. Those criteria should be made available. However, TOPs, not generators, must comply with R5, part 5.1. If the SDT’s intent is to exempt specific generators from following a voltage or Reactive Power schedule, we suggest the following rewrite for R4, with no change to part 4.1: R4. Each Transmission Operator shall specify the generator criteria that will exempt Generator Operators of generators that meet these criteria from compliance with the requirement to maintain a voltage or Reactive Power schedule and

publish or provide such criteria upon request. M4 would have to be rewritten, with item 2) and item 3) deleted. Because 1) exempts a generator from having to meet a voltage of Reactive Power Schedule and 2) exempts a generator from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, being exempt from having to meet a voltage schedule in 1) is equivalent to being exempt from 2). Item 3) is addressed by exemptions stated in VAR-002-3, R1 and R2. 2. R5, part 5.1 should have the phrase “in automatic voltage control mode (the AVR is in service and controlling voltage)” stricken since it would not apply to a Reactive Power schedule. In addition, the TOP should not be required to provide voltage or Reactive Power schedules to exempt generators under part 5.1. Finally, the text box for R5 refers to maintaining a schedule for “normal operations.” “Normal operations” is a critical assumption, which we believe is equivalent to “normal operating conditions.” For example, a generator that experiences a fault on its GSU will be outside of any voltage or Reactive Power schedule during that fault. Therefore, part 5.1 should be rewritten: 5.1. Except for exempt generators, the Transmission Operator shall provide the voltage or Reactive Power schedule for the associated Generator Operator and direct the Generator Operator to comply with the schedule during normal operating conditions. 3. R5, part 5.3 should have the phrase “or Reactive Power” inserted after “voltage.”
1. In R1, a generator that is exempt from having to meet a voltage or Reactive Power schedule is exempt from R1. However, a generator that must meet a Reactive Power schedule should also be exempted from R1 because R1only applies to AVRs in the voltage control mode. R1 should be rewritten as follows: 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) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has been directed by its Transmission Operator to meet a Reactive Power schedule, or 3) has notified the Transmission Operator of one of the following: 2. We suggest R2 have “or Reactive Power” inserted in the following phrase: “…for otherwise shall meet the conditions of notifications for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.” 3. R2, part 2.3 should be moved to M3 since it addresses measures to prove compliance with R2. We suggest the second sentence in M2 be modified as follows: “The Generator Operator shall have evidence to show that the its generator(s) maintained the voltage or Reactive Power schedule provided by the Transmission Operator (either at the location specified by the Transmission Operator or at an alternate location that includes a methodology for converting the schedule from Transmission Operator’s location to the alternate location), or shall have evidence of meeting the conditions of notification for deviations from the voltage schedule provided by the Transmission Operator."
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Yes

(1) M1 – the language in the second paragraph re: Part 1.1 does not match the language of the requirement itself in that the measure refers only to voltage schedules, not voltage schedules 'and associated tolerance bands'. (2) R3 – without further clarification, 'as necessary' will be interpreted to mean as deemed necessary by the Transmission Operator. (3) M3 – the measure in this part contains more details and is more narrow than the requirement itself. The requirement refers to the operation of 'devices to regulate transmission voltage and reactive flow' while the measure refers to the operation of 'capacitive and inductive resources'. Language should be consistent. (4) R4 – the language goes back and forth between 'generators' and 'generating units' – this should be made consistent. Also, the reference to 'associated notification requirements' presumably refers to the associated notification requirements in R5 but this is not specified. (5) M4 – the qualification language that it refers only to generating units 'in its area' appears only in the measure and not in Part 4.1 itself. (6) R5 – neither Generator nor Step-Up is a defined term so they should not be capitalized. (7) M5 – there is a shift in language here. Generally the measures indicate that the responsible entity 'shall have evidence' and that the evidence 'may include'. In this measure, the language is that the responsible entity 'shall have evidence' and that the evidence 'shall include'. This is much more restrictive and may make compliance more difficult as there is no longer flexibility in the evidence that will meet the criteria of the measure. (8) Compliance, Evidence Retention 1.2 – Measures 5 and 6 are not mentioned. (9) Compliance, Compliance Monitoring, 1.3 - The language refers specifically to processes found in the NERC Rules of Procedure. Generally in draft standards, there is just a list of processes that may be used. The reference included in this draft standard is concerning because MB Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure. (10) VSLs, R4 – the words 'of the Generator Operator' are missing from the end of this section. (11) VSLs, R5 – the words 'and associated tolerance bands' is missing from Moderate VSL after 'voltage schedules' and is not fully referenced in Severe VSL. (12) VSLs, R6 – the words 'Documentation specifying requiring tap changes was provided to the Generator Owner but' could be inserted at the start of each of the Lower VSL and Severe VSL.
Although Manitoba Hydro is in general agreement with the standards, we have the following comments: (1) M1 – the language in the measure is that evidence 'must' include which is a shift from typical language that evidence 'may' include. It also seems to be a shift from what is discussed in the rationale that the measure has been updated to include some of the evidence that 'can be used' for compliance purposes as the evidence listed is made mandatory by the 'must'. (2) R1 – footnote 2 and 4 seems to be missing (3) M2 – refers to 'unit' while rest of standard refers to generator. For part 2.3, I believe the reference to 'units' should be to 'Generator Operators'. (4) M3 –the acronym GOP is used while every other reference in the standard is to Generator Operator. (5) M4 – the language between the measure and the requirement differs slightly. The measure requires evidence of notification within 30 minutes of 'the recognition' of a change, while the requirement requires notification within 30 minutes of 'becoming aware' of a change. (6) M5 – there is nothing in the measure that addresses the timeline upon which the Generator Owner is required to provide information. (7) R6/M6 – the requirement and measure refers to both Generator Owner and Generator Operator. Its not

clear whether this is intentional or inadvertent. The words ‘and provided technical justification’ should be added to the end of M6 after ‘tap specifications’. (8) Compliance, 1.2 – there is no time limit on the requirement for a Generator Owner to keep documentation on its step up and auxillary transformers. Its it meant to be for as long as that version is current? (9) Compliance, Compliance Monitoring, 1.3 - The language refers specifically to processes found in the NERC Rules of Procedure. Generally in draft standards, there is just a list of processes that may be used. The reference included in this draft standard is concerning because MB Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure.
(1) VSLs, - not clear why the references throughout the VSLs are to ‘responsible entity’ when the requirements are clear as to an obligation on either the Generator Owner or Generator Operator. Those entities should be listed in the VSLs as they are in the requirements and standards. (2) VSLs, R2, Severe VSL – the word ‘Power’ is missing after ‘Reactive’. Also doesn’t mention that the Generator Operator ‘did not have an exemption’. (3) VSLs, R3 and R4 – would read better if stated ‘the Generator Operator did not make the notification of a change that lasted more than 15 minutes within 30 minutes of the first occurrence of the change as required’.
Individual
Jonathan Appelbaum
The United Illuminating Company
No
Please note that my affirmative ballot vote was in error. We are voting NO on VAR-001. Since there is no catchall section for comments on VAR-001, we are providing comments here. Although We do agree with the removal of duplicative requirements, we are voting No on VAR-001. VAR-001 R2 remove everything after the but not limited to phrase. The various methods to obtain reactive power do not belong in the requirement but they can be included in the measure. VAR-001 R3: Clearly this is something a TOP perfroms but the compliance evidence will be overwhelming. The TOP is being asked to demonstrate that it has constantly monitored reactive and provided direction to operate reactive devices. This will require the retention of the evidence of why a reactive adjustment was necessary as well as the various adjustments made. This would mean maintaining snapshots of the normal operation of the system, records of adjustments, corrections, etc.
Yes
Individual
Angela P Gaines
Portland General Electric Co
PGE appreciates NERC’s efforts to revise VAR-002. The standard as whole is a significant improvement from the previous version. However, R3 still requires a 30 minute notification for notifying the transmission operator (TOP). The 30 minute limit is a challenge for generator operations to meet. The SDT should consider increasing this limit to 60 minutes. In addition,

the requirement should allow registered entities to set up an alternative method to provide real-time AVR/PSS/voltage control device telemetry. This method would eliminate a need for notifying the transmission operator within 30 minutes. Also, the NERC glossary should fully define the term, ‘voltage controlling device’, as stated in R3.
Group
Dominion
Louis Slade
Yes
Yes
Yes. In order to be consistent, Dominion also suggests reviewing the need to use “its associated Transmission Operator” throughout the entire standard (i.e. R1 - “has notified the Transmission Operator”, R2/M2 - “provided by the Transmission Operator”, R6 - “specifications provided by the Transmission Operator”, etc).
Individual
Anthony Jablonski
ReliabilityFirst
1. General Comment - ReliabilityFirst believes that due to the interdependency of the VAR-001-4 and VAR-002-3 standards, the SDT should consider combining the two into a single standard. It would be a natural progression to list a requirement associated with the Transmission Operator having it immediately followed by the associated Generator Owner/Operator requirement. ReliabilityFirst believes the Generator Owner/Operator would benefit from knowing what is being required of the associated Transmission Operator. Specific VAR-002-3 Comments 1. Requirement R6 - The parent Requirement R6 is applicable to the Generator Owner while the sub-part 6.1 specifies the Generator Operator. The same applicable entity listed in the “parent” requirement should be the same as any associated sub-parts. Since only Requirements are enforceable in Reliability Standards, if the Generator Operator fails to notify the Transmission Operator and fails to provide the technical justification per sub-part 6.1, a Possible Violation would be rolled up to Requirement R6. This would not work since Requirement R6 is only applicable to the Generator Owner. ReliabilityFirst completely understands that the Generator Owner is the responsible entity for ensuring that transformer tap positions are changed and that the Generator Operator is the entity responsible for actually performing the change. ReliabilityFirst recommends splitting Requirement R6 and sub-part 6.1 into two separate requirements (i.e., create a new Requirement R7 using the language of sub-part 6.1).
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes

Yes
The VRF of “high” is not justified for any of the requirements. We would suggest a VRF of “medium” or “low”. If the drafting team thinks a VRF of “high “ is justified, some reasoning should be provided by the team. Lack of documented voltage schedules does not mean the system is being operated unreliably. Units are still being operated in AVR mode as required by other schedules and transmission operators coordinate the voltage schedules as needed.
Individual
Bill Fowler
City of Tallahassee
Agree
FMPA
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.

Yes
ERCOT agrees it is clear voltage limits are to be monitored as either SOLs or IROLs. However it seems the SDT could make more changes to clear up more items. A. VAR-001 R3 grammatical: recommend deleting “as necessary” from this sentence. It adds no value and is not needed. B. It appears VAR-001 R4 allows the TOP to not comply with the VAR Standards by utilizing exemptions?
Yes
ERCOT agrees that duplicative requirements should be removed. However, the standard would benefit from additional revisions. A. R1 and R5 should be merged. This could be accomplished in the following manner: “Each Transmission Operator shall notify associated RCs and adjacent TOPs, and specify assigned GOs the a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan required forassigned GOs to operate within System Operating Limits and Interconnection Reliability Operating Limits. B. The second sentence of VAR-001 R2 is not needed. This is not an actionable requirement, but rather is an instruction as to how it’s to be done. The 2nd sentence is not a requirement. C. Recommend deleting from R5.1 the words, “…in automatic voltage control mode (the AVR is in service and controlling voltage).” The standard should establish what needs to be done, and how the GO elects to comply with the requirement should be left to the discretion of the GO. Furthermore, VAR-002 requires the GO to have its AVR in service and in auto, so this requirement is also redundant. D. It appears that VAR-001 R6 is redundant to R5.3. Also see comments on VAR-002 R6.
Yes. ERCOT supports the revisions but recommends that the SDT consider the following additional issues: A. Consider revising R2 as follows: “The generator shall follow the voltage schedule assigned by its TOP.” Otherwise this is effectively a “fill in the blank” standard. As drafted, R2 also establishes “how” entities are required to meet their obligations. The standards should establish what is required and leave it to the discretion of the functional entity to determine how to meet the relevant objective. R3 provides the needed notification.

B. VAR-002 R2 requires GOs to notify TOPs of voltage. This seems to create an unnecessary requirement given that TOPs are obligated to monitor system voltage. C. VAR-002 R2.1 appears to require that GOs maintain the voltage assigned. Consistent with the general principle that the standards should establish what is required, how GOs maintain voltage assignments should be within the discretion of the entity. D. VAR-002 R2.2 is redundant. If GOs have to maintain the voltage assigned, this is unnecessary. E. VAR-002 R2.3 is redundant if a GO has to maintain the voltage assigned. F. VAR-002 M2 includes a statement that has a “will” in it. This effectively establishes a requirement. Measures are means of demonstrating compliance, they are not requirements. The measure should be revised accordingly. G. VAR-002 R3 should state that the notification is not required during startup or shutdown. A TOP can determine from telemetered information when a unit is operating below their lower stability limit. Requiring reporting of AVR/PSS status coming on/going off line is not necessary and creates unnecessary distractions that could undermine reliability. H. The 2nd sentence of R3 is redundant with the 1st. If notification is required within 30 minutes it is implicit that the entity does not have to notify within 15 minutes? I. If a GO maintains the assigned voltage, the status of a GO’s AVR is irrelevant. If a GO failed to maintain the assigned voltage they are in violation of R2 regardless of the reason. M3 seems to unnecessarily create the potential for double violation issue on a reporting obligation.J. The standard should make clear that telemetry on status of AVRs and PSSs to TOPs meets this notification obligation. The term ‘notify’ seems to imply a manual written or verbal communication. K. VAR-002 R4 second sentence dealing with 15 min language- - please refer to R3/M3 comments. L. VAR-002 R5 – This requirement is unnecessary if GOs have to respond to any reasonable data request from their TOP. M. VAR-002 R6 is redundant with R2. If a GO has to maintain assigned voltage, and adjusting taps is necessary to do that, then this instructional requirement is not needed. If R6 is kept, in VAR-002-3 Standard the entity changes in R6.1. VAR-001-4 states the TOP will work with the GO in R6. Then in VAR-002-3 it states the following: 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 Operator cannot comply with the Transmission Operator’s specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification. Why does it change from the GO to the GOP? The SDT should address the differences within VAR-002-3 to mirror R6 in the VAR-001-4 Standard.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We support this direction and the SDT’s decision to not reiterate or duplicate the voltage assessment requirements already addressed by the FAC and TOP standards.
Yes

We support the SDT's proposal to remove the requirements that may be redundant with other standards. We do not have any comments on the requirements, Measures or VRFs, but we do have some comments on the VSLs: a. R1: The word "schedule" after "system voltage" is missing from the VSL. b. There is inconsistency in the tense used in various VSLs – some are in present tense while others in past tense. Please review and revise as appropriate.
We agree with most of the proposed changes, but would suggest the following changes to more effective convey the intent of Requirement R3 and Measure M3. a. R3: The wording "the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator" is not a direct action and may not be measurable. We suggest to revise it to read: "the Generator Owner shall implement the transformer tap positions according to the specifications provided by the Transmission Operator…." b. M3: We suggest it be reworded to require demonstration of compliance rather than to require actions which should have been stipulated in the requirement. Specifically, we proposed the last part in Measure M3 be revised to: "…therefore, if a status change lasts more than 15 minutes, the GOP shall provide evidence such as system log, electronic message or a transmittal letter that it notified its associated Transmission Operator within 30 minutes of when the change first occurred." We further propose that the SDT insert the evidence language into the first sentence of Measure M3 which asks for evidence that the Generator notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3. We assess the changes proposed under Q2 and Q 3, above, are not substantive and do not materially change the intent or content of the standards. Therefore, if the standards receives 2/3 majority approval at the ballot, these changes can be implemented and posted for recirculating ballot without having to post and ballot the standards for a successive ballot.
We support the proposed VRFs and VSLs.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Marcus Pelt
Yes
R1: The modifications in this version of VAR-001 R1 are good because they standards that are now enforceable, particularly FAC-011 and FAC-014. M2: All Transmission Operators are required to run contingency analysis on the real time system on a periodic basis per TOP-008-1 R4. We suggest modifying VAR-001 M2 to state: "If the assessment is performed in the Operations Planning Horizon, Transmission Operators shall provide copies of assessments used as the basis for how resources were scheduled." M3: Actions are not always required to be taken because of automatic settings of reactive devices. We suggest modifying VAR-001 M3 to state: "Each Transmission Operator shall have evidence that actions were taken as necessary to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments." R5.3 states, "The Transmission Operator

shall provide the criteria used to develop voltage schedules and associated tolerance bands to the Generator Operator within 30 days of receiving a request.” We suggest that this requirement is removed due to administrative burden. We recognize the need for transpency; however, this requirement does not serve a reliabity purpose.
Yes
: The High VSL for VAR-001 R4 should be changed from the proposed state to "The TOP has exemption criteria, but did not notify the GOP." As it is currently written, the TOP satisfied R4, but simply cannot show documentation to prove the satisfaction. The proposed change wording focuses on the TOP not satisfying the requirement. The first clause in the Severe VSL for VAR-001 R5 should be corrected to state “voltage or Reactive Power schedules.” In addition, the Severe VSL for VAR-001 R5 should have another OR clause to include the failure to comply with R5.3.
Adding "testing" to VAR-002 R1 was a good move. This will serve to avoid nuisance notifications for routine testing. Modifying VAR-002 R2 to allow the TOP to specify notification instructions is a good move. Each TOP will be able to specify notifications appropriate for characteristics of their transmission system. Removing the VAR-002 R3 notification of duration was a good move - the GO often does not know how long it will be out until some troubleshooting is performed. Splitting the old R3 into new R3 and new R4 was a good move. This separates two distinct types of trouble. The addition of "after becoming aware of a change in reactive capability" to the new R4 was a good move - this change is not always immediately evident. M4 should be modified to match R4 - "after becoming aware of a change needs to appear in M4".
The removal of "up to 45 minutes for the R2 VSL was a major improvement. The comma in the second and third OR statements of the Severe VSL for VAR-002 R2 is not needed. The comma in the second OR statement of the Severe VSL for VAR-002 R6 is not needed.
Individual
Brett Holland
Kansas City Power & Light
Yes
I agree with the approach to condense standards if they are duplicated in other standards.
NO. R2 is the part of VAR-002 that I disagree with because the Transmission System Operator is monitoring the system voltage and notifies each generating facility when they need to raise/lower voltage in that particular area of the system. If the voltage at the generating facility is high/low the TSO has received an alarm and will be notifying the plants control operator to correct the voltage and there already is a requirement for the control operators to comply with the TSO request.
No.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC

Yes
No
ATC agrees with the approach in removing any duplicate requirements. ATC also has a couple comments and is recommending the following changes for the drafting team to consider: 1. For consistency, Measure M2, 2nd sentence should be reworded as follows: "For the operational planning time horizon, Transmission Operators shall "have evidence of assessments" used as the basis for how resources were scheduled" The current wording of "shall provide copies" imposes an action that is not included in the associated requirement R2. 2. The following from requirement R2: "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" implies that all of the items listed need to be considered. If the intent is that the items are intended to be examples it is suggested that the words "including , but not limited to" be replaced by "such as".
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Xcel Energy appreciates the hard work of the Standard Drafting Team. We recognize that significant effort has been put into the modifications of the VAR-001 and VAR-002 standards and we applaud the direction the team is moving. We are voting Negative on VAR-001-4 for one reason which we explain below. Xcel Energy believes that the WECC Regional Variance should not replace R4 in the NERC standard based on the rationale provided for modifications to the proposed R4. Instead, WECC Regional Variance Requirement E.A.13 should be removed and the remaining Regional Variance Requirements should supplement the NERC Requirements in the Western Interconnection. As proposed, the NERC standard states that the TOP is not bound to provide a voltage schedule for each BES generator; however , due to the WECC variance, the TOP would be found in violation if any BES Generator was not provided a voltage schedule. In order to resolve the issue, Xcel Energy asks the drafting team to delete E.A.13 in its entirety and modify the language of the Regional Variance to state that the additional requirements are for in addition to the NERC requirements. Once this modification is made, Xcel Energy could support the proposed standard.
Yes. Xcel Energy appreciates the hard work of the Standard Drafting Team. We recognize that significant effort has been put into the modifications of the VAR-001 and VAR-002 standards and we applaud the direction the team is moving. We are voting Negative on VAR-002 for one reason which we explain below. Xcel Energy understands that the existing language in the VAR-002 standard uses the term "status change" but believe that this term is not well defined and is subject to different interpretations. AVRs and PSSs are designed to cycle based on the parameters being monitored by the devices. This as-designed cycling may be interpreted as a status change. We note here that the drafting team does not use the term status change in its

rationale statement. Instead, the rationale statement is much clearer in meaning than the proposed requirement language. To address Xcel Energy's concern, we request that the drafting team replace the first sentence in Requirement R3 with the following sentence. (We believe that this change does not constitute a significant modification but is instead providing more clarity in the requirement language based on the wording of the Rationale for Requirement R3.) "Each Generator Operator shall notify its associated Transmission Operator when the AVR, power system stabilizer, or alternative voltage controlling device goes out of service within 30 minutes of the change."
If the drafting team makes the requested modifications to the requirements, Xcel Energy has no concerns with either the VSLs or VRFs.
Individual
Lynda Kupfer
Puget Sound Energy
- The implementation period might be as short as one day as the Effective Date section is currently formulated. For example, if approval occurs on 12/31/2013, the first day of the first calendar quarter after that date would be 1/1/2014. A short implementation period for this standard is appropriate; however, language such as "The first day of the first calendar quarter that is one month beyond the date that this standard is approved..." would ensure that a minimum of one month is available for implementation.
Yes
- The first paragraph of the Regional Variance section of VAR-001 should be updated to reflect that requirements R3 and R4 of the current standard are requirements R4 and R5 in the proposed standard. - M4 should be updated to reflect that the Generator Operator "must notify its associated Transmission Operator within 30 minutes of when the change first occurred. after becoming aware of the change in reactive capability" to be consistent with the wording of R4.
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
No.
Individual
Silvia Parada Mitchell
NextEra Energy
Agree
MidAmerican
Individual

Rjick Terrill
Luminant Generation
Yes
Yes
Luminant appreciates the work of the SDT and agrees that most of the revisions are appropriate, and that the intent of the SDT to allow for more than one method of voltage support is correct. However, as written, VAR-002, R2, does not clearly identify that generators can provide voltage support by a method other than maintaining a voltage schedule, continuously monitoring voltage and reporting deviations from the voltage schedule. In some areas of the country, the TOP monitors the voltage at all busses in it area, including the busses connecting generators, and directs generators to modify reactive output as the TOP requests. Luminant believes the language of VAR-002, R2 should be modified to provide clarity as follows: R2. Unless exempted by the Transmission Operator, each Generator Operator shall provide generator voltage support or Reactive Power support (within each generating Facility's capabilities4) as follows: [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 provide voltage or Reactive Power support directed by the Transmission Operator. 2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the request cannot be met. 2.3. When directed by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule3 (within each generating Facility's capabilities4) provided by the Transmission Operator, and shall meet the conditions of notification for deviations from the voltage schedule provided by the Transmission Operator. 2..3.1 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. With this proposed language, the GOP would have to maintain a voltage schedule and report deviations only if that is the normal method of voltage support requested by the TOP. 2.3 and 2.3.1 would only apply to a GOP that maintains a voltage schedule. The measures for 2.1 and 2.2 would include operator logs, voice recordings, etc.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
City of Austin dba Austin Energy (AE) agrees with removing duplication. AE does not have any comments about the requirements, but requests the SDT review the VSL for R2 because the text does not match the requirement text.
Yes.

No. Because NERC has not provided an area for "Additional Comments," we are adding them here. The City of Austin dba Austin Energy (AE) commends the Standard Drafting Team's efforts related to Project 2013-04. The quality of the standard is enhanced over previous approved versions, providing additional clarity and compliance sensitivity. AE respectfully submits the following comments on VAR-001-4 and VAR-002-3 to the Standard Drafting Team (SDT): VAR-002-3, R1, Pertaining to the phrase "… unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has notified the Transmission Operator…" AE recommends the SDT clarify whether the TOP may exempt all the units represented by a GOP, or instead, specific generating facilities or a generator bus. AE suggests altering the language to read "… unless 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator…" This change will make the language in VAR-002-3 R1 consistent with the language in VAR-001-4 R4. VAR-002-3, R2.3: The requirement makes it mandatory for Generator Operators to monitor the voltage at the location specified in the voltage schedule or have a methodology for converting the scheduled voltage specified by the TOP. This may imply that the Generator Operator should make voltage corrections independent from the TOP. AE believes that maintaining the appropriate transmission level voltage is the key for sustaining system stability and that responsibility falls on the TOP. Because the TOP already monitors the transmission level voltages, the R2.3 requirement for GOPs to monitor voltage is redundant and may create a situation where the TOP and GOP do not agree on the monitored value (i.e. the voltage readings can be different due to step-up voltage equipment). To avoid confusion and potential compliance ambiguities, AE suggests the standard specifically state TOPs are responsible for monitoring the system voltage schedule and notifying the GOP when voltage drifts outside acceptable parameters. This appears to be a common practice of operating the grid. The GOP will be responsible for meeting the reactive support requested by the TOP. If the GOP cannot meet the reactive support requested by the TOP, the GOP should have to notify the TOP. AE suggests the following: Add "Transmission Operators" under R4 – "4.3 Transmission Operators", and alter R2.3 to: "Each Transmission Operator shall monitor the system voltage and notify its associated GOPs for additional voltage support if system voltage fails to meet the voltage schedule. If the GOP cannot meet the reactive support requested by the TOP due to equipment limitations, it shall notify the TOP of the limitations within 15 minutes. VAR-002-3, R4: AE believes the phrase "a change in reactive capability" is vague. As written, even the slightest change in reactive capability must be reported to the TOP. Is it the SDT intent the TOP be notified if a reactive capability (leading or lagging) of a generation resource changes by 1 MVAR? Detecting and reporting small reductions in reactive capability will create onerous reporting. AE recommends the following for R4: "Each Generator Operator shall notify its associated Transmission Operator within 30 minutes that a resource's reactive capability changed by 20 MVAR or 10%, whichever is greater, of the previously provided reactive capability due to factors other than a status change described in Requirement R3."
Individual
David Jendras
Ameren

Yes
No
We request that the SDT leave the language as currently used in VAR-001-2, R4.
We request that the SDT support adding to R3 the “…after becoming aware of…" language now proposed for R4. This will help reduce the number of unnecessary GOP notifications to the TOP.
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
Yes
FMPA appreciates the efforts of the SDT to remove some of the duplicative requirements of the VAR standards with other standards (e.g., TOP and FAC standards). However, FMPA is voting Negative because we believe more requirements ought to be treated in the same fashion as described in our earlier comments on the September posting, as provided in a mapping document submitted directly the the SDT to better illustrate those duplications, and as summarized below. VAR-001-4 R2 is duplicative of the requirements of TOPs to plan for and operate to SOLs in the TOP and FAC standards. In order to plan to and operate to SOLs, TOPs must schedule sufficient reactive resources, or they will violate those requirements (just as must-run generators need to be scheduled, yet those are not discussed within the standards). Operating to SOLs is results based, VAR-001-4 R2 is not. VAR-001-4 R2 ought to be deleted. VAR-001-4 R3 is duplicative of requirements of TOPs to plan for and operate to SOLs as described above. As far as TOPs ability to direct, that is covered in TOP-001. VAR-001-4 R3 should be deleted. Although FMPA supports both VAR-001-4 R1 and R5, we wonder if there is some duplication between those requirements and whether they can be combined into a single requirement.
FMPA appreciates these changes. However, VAR-002-3 remains duplicative of other requirements within the standards VAR-002-3 R2, bullet 2.3 is duplicative of TOP-001-2 R1. Both require the GOP to follow the direction of the TOP. Bullet 2.3 should be deleted. VAR-002-3 R5 is duplicative of TOP-003-2 and should be deleted. VAR-002-3 R5 requires the GO to provide the TOP information about the GSU. TOP-003-2 R5 requires the GO to submit data as specified by the TOP. The TOP cannot perform their obligations of VAR-001-4 R6 to specify GSU tap positions without the data of VAR-002-3 R5; however, the TOP will ask for that data in accordance with TOP-003-2 R3. Hence, these requirements are redundant and VAR-002-3 R5 ought to be deleted. FMPA also wonders how duplication between TOP-003-2 that gives TOPs a carte blanche opportunity to develop data requests on any information they need and the notification requirements of VAR-002-3 will be managed. In other words, the TOP can develop their TOP-003-2 data specification to include the notification requirements of VAR-002-3 and as such GOPs would be subject to double jeopardy risk.
Group

Tennessee Valley Authority
Brandy Spraker
Yes
Yes
The SDT is requested to clarify the word “directions” as used in M3. The word “directions” is close to, but not, the word “directive” which has a very specific meaning. If the intent is to capture directives, then the word directives should be used. If the intent is to capture communications that are not directives, then the word “directions” should be replaced with wording that is not so close to the word “directives.” Current M3 draft language: M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments. The SDT is requested to consider a modification to R4: Current R4 draft language: R4. The Transmission Operator shall specify the criteria that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements. Suggested modification to R4: R4. The Transmission Operator shall specify the criteria, ADD: “if any” that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements.
Yes
No comments
Individual
Kathleen Goodman
ISO New England Inc.
Agree
IRC SRC
Individual
Karen Webb
City of Tallahassee - Electric Utility
Agree
FMPA
Group
PacifiCorp
Ryan Millard
Yes
Yes
PacifiCorp supports MidAmerican's comments.
The following change to requirement R4 is recommended: “Reactive capability changes due to change in the wind speed for wind generators or a change in the solar resource for solar

facilities do not require Transmission Operator notification." Given the variable nature of wind, the reliance of weather forecasting does not rest explicitly with the GOP. The TOP has access to weather forecasting that would make the need of notification by the GOP unnecessary. Additionally, PacifiCorp supports the following comments from MidAmerican: We support the deletion of the language regarding notification of the expected duration of a change in status. At the time a status change occurs it is often difficult to provide a meaningful estimate of the duration of the change. Requirement 3 should be revised to state – Notification must be made within 30 minutes of becoming aware of the change from automatic controlling voltage for the AVR, and from in-service of the PSS. Measure 3 should be revised to reflect this as well. The revised VAR-002 R2.1 removes the 15 minute deviation criteria for notification by Generator Operators to Transmission Operators. The revised VAR-001-4 requires Transmission Operators to provide notification requirements. The drafting team in the consideration of comments explained "In an effort to remove prescriptive notification requirements for the entire continent" the change was made. This leaves the Generator Operators at the mercy of Transmission Operators who could potentially set a no deviation criteria. It is recommended that a comprise be struck by specifying a limit on the criteria such as "no less than 15 minutes".
Individual
Robert L. Dintelman
Utility System Efficiencies, Inc.
Yes
Yes
Many of the other standards that require the provision of this sort of information to the RC and neighboring entities includes a requirement that the entity respond to comments/concerns from the copied entities. Why not here? R2 appears to be a little ambiguous; does this apply to all contingency conditions? Just N-1? Only those chosen by the TOP? This would appear to be hard to determine compliance by the Region. It looks like R6 assumes that the GO has a non-LTC transformer. We are seeing LTCs in generation facilities; shouldn't this be modified to address the LTC GSUs? For M2 and M3 particularly, Evidence Retention could require a lot of data for 12 months.
For R2, what about the situation where the generator cannot actually influence the voltage? There may be a significant amount of hours where they can't keep the voltage in range. For M2, for a generator that does not have an AVR, what type of evidence is required to show compliance for 8760 hours per year? Sounds like a lot of evidence potentially.
No
Group
Duke Energy
Colby Bellville
Yes
Yes

Duke Energy approves of the approach of removing duplicative requirements based on other standards. Duke Energy seeks clarification on the definition of “system voltage schedule” and believes that once this is more clearly defined, it should be added to the NERC Glossary of Terms. The Rationale for Requirement 1 discusses the TOP setting voltage or Reactive Power schedules with associated tolerance bands. However, Requirement 1 makes no mention of using Reactive Power schedules. Is the use of Reactive Power Schedules implied in Requirement 1? Duke Energy suggests changing “Each Transmission Operator shall schedule” to “Each Transmission Operator shall maintain” in Requirement 2 for more clarity. In Duke Energy’s opinion, not all reactive resources can be “scheduled” in order to regulate voltage levels. For example, SVCs cannot be scheduled, the reactive resources of an SVC dynamically change to maintain set voltage levels. The TOP needs to ensure that adequate static and dynamic reactive resources are availble to the System Operator in real time to support the Reliability needs of the BES. Reliability Studies are performed in the Operations Planning horizon to ensure that reactive resources are adequate to support the planned BES configuration.
No. Duke Energy does not agree with the revisions made. Duke Energy is unclear whether the exemptions referenced in R1 and R2 in VAR-002-3 are the same as the exemptions created in VAR-001-4 R4. We believe using the word “exempted” in multiple requirements without identifying the origin of the exemption is a cause of confusion. Requirement 2 - Revise R2.1 to read, ” When a generator’s AVR is out of service, the generator does not have an AVR, or is not in a TOP approved mode of AVR operation as specified in R1, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. “ The VRF/VSL for Requirement 2 would need to be modified if this change is made. Requirement 3 – Duke Energy is unclear as to what is considered an alternative voltage controlling device. Duke Energy prefers the language in the previous draft of this standard which states, “Each Generator Operator shall notify its associated Transmission Operator of a status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability within 30 minutes of the change. If the status has been restored within the first 15 minutes of such change, then there is no need to call the TOP. “ The language in the previous draft provides more clarity on what would prompt notification from a GOP to a TOP based on status or capability change. Requirement 5 – Duke Energy would like the SDT to review and verify that the Transmission Planner, and not the Planning Authority or Planning Coordinator, is the correct functional entity for this requirement. Lastly, Duke Energy would like to clarify that we encouraged our ballot body members to vote “Negative” on this ballot for reasons stipulated above. However, one of our ballot body members mistakenly voted “Affirmative” which was in error. Our decision to vote “Negative” on this ballot was unanimous among all those involved. We apologize for any confusion this may have caused.
See our comments on VAR-002 Requirement 2.
Individual
Melissa Kurtz

US Army Corps of Engineers
Agree
MRO NSRF
Group
Western Area Power Administration
Lloyd A. Linke
Agree
US Bureau of Reclamation.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
Yes
An additional change should be made – R3 should state that when real-time status is provided to the TOP electronically there is no need for additional notification.
Time requirements are not necessarily arbitrary, and it is in fact important to establish explicit and meaningful criteria regarding the acceptable time (and magnitude) of voltage schedule deviations. The principal reason that VAR-002 has been so troublesome in the past is that one could interpret a 10 MW hydro unit being out of the bandwidth by 0.1 kV for 1 minute as constituting a violation, despite there being no meaningful impact on BES reliability. There are moreover many occasions when a the system voltage unavoidably strays briefly outside the bandwidth due to a disturbance or because there are step-changes in the TOP's voltage schedule. VAR-002-3 makes a slight movement in the right direction by stating in R2 that a unit must keep within the bandwidth or, "meet the conditions of notification," but there is nothing in VAR-001 or 002 to require TOPs to create justifiable requirements in this respect. We presently suffer under a system in which meaningless violations are spawned by abusive practices, such as establishing a bandwidth of only +/- 0.5%, and VAR-001 and 002 should be revised in a fashion that prohibits such practices.
Individual
Gerald G Farringer
Consumers Energyu
Yes
Yes
This is a two part question with only one YES/NO answer. YES we agree with the approach. YES we have questions or comments on the remaining revised requirements. In R4, there should be a statement that the TOP will publish the exemption criteria to GOPs in the area. A consideration should be made to reserves R1 and R5. It is imperative both get the voltage schedules but if the GOP does not have them there is no control.
It is important to clarify the statement of "notification requirements." In the context of VAR-

002 this term refers to the notification from the GOP to the TOP on status of the AVR, Ability to follow the voltage schedule or the status of the unit. We would suggest the timing on VAR-002 R3 be similar to R4 in that the clock starts at the awareness of the GOP of a status change. VAR-001 clearly defines a Voltage or Reactive Power schedule. We suggest this be done in VAR-002 for consistency rather than the footnotes provided.
Individual
Chris Scanlon
Exelon Companies
Yes
Yes
Yes, agree with approach, no additional comments relating to requirements. Exelon companies would vote Affirmative for VAR-001-4 if it were being balloted separately from VAR-002-3.
Exelon appreciates changes made to the standard the current revision is a significant improvement on the previous draft version. As mentioned above, we support VAR-001-4 as written but feel important issues remain unaddressed with VAR-002-3 and will therefore vote Negative. Our principal concerns include: VAR-002-3 Effective Dates. The Implementation Plan for VAR-001-4 and VAR-002-3 requires the new Standard revisions to be implemented the first day of the first calendar quarter after applicable regulatory approval. Although the Implementation Plan justification states that the VAR-002 standard “cannot go into effect without the new TOP schedules and notification requirements” it does not address the implementation associated with changes to VAR-002 with respect to status notifications. This is not sufficient time to allow generating units to implement training of operators and procedural changes necessary to implement the proposed changes to notification requirements associated with the AVR, PSS or alternative voltage controlling device. We suggest at least a 6 month implementation period following regulatory approval. VAR-002 R1 or in the applicability section of the standard. This standard or requirement does not account for dispersed Generation (such as wind or solar as found in the new BES definition). These generators may not have traditional AVR, may only provide limited Reactive resources and the individual elements may not have AVR or be capable of operating in Voltage control mode. VAR-002-3 R2.3 Exelon believes it is reasonable to allow the GOP to monitor the voltage at the location specified in their TOP issued voltage schedule by allowing the GOP to monitor at a different location by applying a methodology for converting the voltage monitored; however, the conversion method should be communicated and agreed to by the Transmission Operator. There is not a one for one conversion between grid voltage and terminal voltage and both parties should agree on the conversion method and monitoring point to avoid any future audit or implementation issues. VAR-002-3 R3 Exelon agrees with the fifteen (15) minutes to allow a GOP time to resolve an issue before having to notify the TOP of a status or capability change; however, postponing the notification by 15 minutes to alleviate short term / nuisance notifications has the effect, as written, of shortening the notification window to 15 minutes. Fifteen minutes is not a reasonable timeframe for such notifications to occur,

especially in large dispersed fleet operators where the GOPs do not communicate directly to their TOP and must notify via a third party (e.g., an independent generation dispatching organization). Exelon suggests that the 30 minute notification timeframe for a status change on the AVR, PPS or alternative voltage controlling device be started following the inability to restore within 15 minutes. VAR-002-3 R4 Exelon suggests that the VAR SDT provide guidance to the industry on examples of reactive capability changes that would require notification to the TOP within 30 minutes after becoming aware of a change. The only guidance provided to date is in the VAR-002 Compliance Analysis Report dated August, 2010.
We understand that R3 and R4 are binary requirements, (did or did not notify in 30 minutes), but it seems unreasonable that a complete failure to notify would have the same VSL as a notification that is one or five minutes late.
Group
SPP Standards Review Group
Robert Rhodes
Yes
We thank the drafting team for taking this stance in not establishing details in the VAR standards and relying on those that already exist within defined SOLs and IROLs. Adding additional detail here would be redundant and possibly conflicting with requirements in other standards.
Yes
We agree with the retirement of redundant requirements and suggest that the drafting team delete R2 and R3 in addition to the other deletions already proposed. R2 is redundant with the pending TOP-002-3, R1. R3 is redundant with pending TOP-001-2, R7 and R9.
Yes. We also offer the following comments on the two standards. Generic Comments on VAR-001-4 We recommend changing ‘real time’ in the Purpose to ‘Real-time’ as defined in the NERC Glossary of Terms. We suggest rewording R1.1 to the following: ‘Each Transmission Operator shall provide a copy of the voltage schedules as specified in R1 to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of such a request.’ Although we have proposed deleting R2, if the drafting team decides to keep it, we recommend deleting the last sentence in R2. It is really an example and doesn’t contribute substantially to the requirement. We also recommended deleting R3 but if the drafting team decides to keep it, we suggest adding ‘to operate within SOLs and IROLs’ following ‘as necessary’ at the end of the requirement. The use of the term ‘direct’ in R3 and R5.1 lead to implications of issuing directives. To get away from this situation, we suggest substituting ‘instruct’ for ‘direct’. This change will also need to be reflected in the Measures and the VSLs. Since R4 contains an exemption for R5, we suggest reordering requirements R4 and R5 such that R5 becomes R4 and R4 becomes R5. That way the exemption follows the requirement. We suggest the drafting team delete the phrase ‘…at the Transmission Operator’s discretion.’ at the end of R5. We suggest changing ’associated’ to ‘applicable’ in and deleting the redundant phrase at the end of R5.1. The requirement would then read: ‘The Transmission Operator shall provide the voltage or Reactive Power schedule to the applicable Generator

Operator.' The Measure will also need to be revised to correspond with the revised requirement. We recommend adding 'for that criteria' following 'request' at the end of R5.3. We recommend changing the Time Horizon in R6 to Long-Term Planning since the Transmission Planner is typically the entity that will determine when a tap change is necessary and will notify the Transmission Operator that it needs to be done. In the Rationale Box for R6 there is a reference to VAR capability and tap setting. We suggest rewording that sentence to the following: 'If the tap setting is not properly set, then the VARs available from that unit can be affected.' The Severe VSL for R3 contains 'real-time'. It needs to be 'Real-time'. Generic Comments on VAR-002-3 The use of the term 'direct' in R2.2 lead to implications of issuing directives. To get away from this situation, we suggest substituting 'instruct' for 'direct'. This change would need to be reflected in the Measure 2.1 and 2.2 and the VSL also. We suggest changing the notification timing requirements in R3 to the Generator Operator must notify the Transmission Operator within 30 minutes of the change of AVR status unless the AVR has been restored to service. In the second sentence in the Rationale Box for R3, use 'provide' instead of 'provided.' In the Rationale Boxes for R5 and R6 there is a reference to VAR capability and tap setting. We suggest rewording that sentence to the following: 'If the tap setting is not properly set, then the VARs available from that unit can be affected.'
We suggest the following change for the High VSL for R2. The responsible entity did not have a conversion methodology when it monitored voltage…' We recommend replacing the word 'directive' with 'specification' in the Severe VSL for R6.
Individual
Texas Reliability Entity
Texas Reliability Entity
(1) Under the currently enforceable TOP standards, there is a requirement to operate within SOLs and IROLs (in TOP-004-2 R1). However, in the proposed TOP standards currently filed at FERC for approval, the wording of this requirement changed. In TOP-001-2 R8 thru R9, the TOP only has to operate within SOLs that "deserved increased attention" according to the rationale stated in the proposed Standard. What effect does that change have on these VAR requirements, and the stated rationales? (2) If it is the SDT's intent for R2 and R3 that the TOP operate within voltage SOLs, then we suggest rewording R3 to remove "as necessary" to say "within System Operating Limits" or "under normal and Contingency conditions" to match R2. (3) The VSL language for VAR-001-4 R2 and R3 does not match the wording in the requirements. If the intent is to require operation within SOLs and IROLs as suggested by the VSLs, then the requirements should expressly say so. If it is not, then the VSLs should be revised to match the requirements. (4) For VAR-001-4 R1 and R5, should there be a process to provide feedback to the TOP on the voltage schedule? For example, if the TOP sets the voltage schedule in a manner that requires the generator to be at or near a reactive limit for the unit, then the unit may not be able to provide the necessary reactive support under a contingency situation.
(1) The status and capability notifications in R3 and R4 may be directly or indirectly in conflict with TOP-005-2a Attachment 1, Item 1.2.4, IRO-005-3.1a R1.1 and R12, IRO-002-2 R5, IRO-003-2 R2, TOP-006-2 R1 and R2, TOP-008-1 R4 and possibly future TOP-003-2 R1. Will the TOP

and RC be able to satisfy their obligations under these other standards in view of the proposed GOP reporting parameters? (2) In VAR-002-3 R4, does the “reactive capability” include static capacitive or reactive devices that are behind the fence (for example, static capacitors and reactors installed on the low voltage feeders at wind plants to meet power factor requirements). Would this requirement apply to such devices if they are not included in the Bulk Electric System per the new BES definition?
Individual
Dave Willis
Idaho Power Company
Yes
Yes
Yes, exempting the intermittent outages of AVR’s and only requiring notification for extended interruptions is an improvement and lessens the documentation necessary to show compliance.
No
Group
ACES Standards Collaborators
Jason Marshall
Yes
Yes this is clear. We thank the drafting team for removing the duplication from the previous draft.
Yes
(1) Requirement VAR-001-4 R1 is vague and ambiguous and may be duplicative of VAR-001-4 R5. It requirements need further refinement. First, it states that the TOP shall specify “a system voltage schedule”. This is singular. A system always has multiple schedules for generators, capacitor banks, reactors, etc. It does not have a single voltage schedule. Second, what equipment or facilities is the voltage schedule supposed to apply? Is this supposed to be the voltage schedule for a generator? Is this supposed to the voltage for reactor or capacitor switching? Is this supposed to be the voltage limits on a transmission bus? Schedule would tend to imply a level of control and, thus, not a limit but the simple reality is that the requirement is vague, ambiguous, and unenforceable as written. Third, if the requirement applies to voltage schedules at generators, it is duplicative to VAR-001-4 R5 because this already compels the TOP to provide voltage schedules for generators. Please provide additional clarifications in the requirement. (2) We appreciate the drafting team removing duplicate requirements. This version of the standard has been improved greatly. However, we still believe there is some duplication that needs to be addressed. For example, VAR-001-4 R1 requires a TOP to “specify a system voltage schedule… as part of its plan to operate with System Operating Limits and Interconnection Reliability Operating Limits” while VAR-001-4 R2 requires the TOP to “schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions”. How does a TOP specify a voltage schedule per R1 and

not also schedule sufficient reactive resources per R2? The TOP can't maintain the voltage schedule without scheduling sufficient reactive resources. Please eliminate the duplication. (3) VAR-001-4 R2 is also duplicative of VAR-001-4 R3. R2 requires the TOP to "schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions" while R3 requires the TOP "to operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow". How does the TOP schedule sufficient reactive resources without regulating transmission voltage and reactive flow? The TOP would be operating the voltage-regulation devices when they schedule sufficient reactive resources since the voltage-regulation devices are reactive resources. If the purpose was to delineate by time frames implied by the use of "Real-time Operation" in R3 and "schedule" in R2, the requirements need further refinement to be clear that the targeted time frames are supposed to be different. Furthermore, the Time Horizons for both R2 and R3 are duplicate covering Real-time Operations, Same-day Operations, and Operational Planning which would imply that different time frames are not intended. Please eliminate the duplication or clarify the time frames as appropriate. Detailed application guidelines would help eliminate some of the confusion. (4) Part 1.1 meets P81 criteria and should be retired. The requirement meets Criterion A (overarching) because it "does little, if anything, to benefit or protect the reliable operation of the BES" and meets criterion B4 – Reporting because it requires the TOP to report to another party and has "no discernible impact on promoting the reliable operation of the BES." The mere fact that Part 1.1 only requires reporting upon receiving a request is supportive that it has no impact on reliability. If it did materially support reliability, the RC would be required to have the data and the TOP would be obligated to provide it. Please remove Part 1.1. If Part 1.1. persists in the next draft, we request that the drafting team provide written justification for why these requirements do not meet P81 criteria and actually materially support reliability. (5) Measure VAR-001-4 M2 is inconsistent with the main requirement R2 and needs to be modified. M2 proposed that the TOP shall have evidence of scheduling resources based on their system assessment. While we agree this is likely the method the TOP will use to schedule resources, the simple fact is that it is not part of the requirement and cannot be compelled in the measure. Please modify the measure to be consistent with the requirement. (6) The second sentence of R2 is an explanation and not a requirement. Thus, it should be moved to the application guidelines section. We understand that FERC previously directed NERC to include use of controllable load as a reactive resource because it was not one of the explicitly listed reactive resources. FERC likely included this statement as evidenced by the first sentence of paragraph 1879 of Order 693 to further a policy goal of expanding the use of demand side management (DSM). At the time the order was issued, DSM was in its infancy. Today, DSM has become ubiquitous as demonstrated by the almost 40,000 MW reported in the NERC 2013 Summer Assessment. Given that all organized markets include at least one DSM product, its proliferation will only continue. Thus, the policy goal has been clearly met and specific mention in NERC standards in no longer necessary. In fact, an equally efficient and effective alternative would be to eliminate specific references of any type of reactive resource by striking the second sentence in its entirety. (7) The Time Horizons for VAR-001-4 R3 are inconsistent with the requirement. R3 specifically states that it deals with Real-time operation. Thus, how could Operational Planning and Same-day Operation be applicable? These timelines are conflicting and need to be modified. (8) For requirement VAR-001-4 R4, why can't the GOP make a self-determination that it meets the TOP criteria? Is the TOP obligated to make a determination or to simply supply the criteria to the GOP? The RSAW indicates that the auditor will not determine if the GOP received pre-authorization from the TOP. Thus, the requirement should either be modified so that audit practices will have to be modified or aligned with how the RSAW indicates compliance will be assessed. We recommend that the drafting team work with NERC compliance to align the requirement with the RSAW language. (9) VAR-001-4 R5 should be modified to clarify that the TOP is not required to provide a voltage schedule to all generators but only to those generators that it determines it needs to provide reactive supply. A TOP may determine that a generator is too small to control voltage at its location and that it does not need to provide a voltage schedule for this generator. Including all generators is unnecessary for reliability. (10) Part 5.3 meets a P81 criterion and should be retired. The requirement meets Criterion A (overarching) because it "does little, if anything, to benefit or protect the reliable operation of the BES" and meets criterion B4 – Reporting because it requires the TOP to report its criteria to another party and has "no discernible impact on promoting the reliable operation of the BES." The mere fact that Part 5.3 only requires reporting upon receiving a request is supportive that it has no impact on reliability. If it did support reliability, the GOP would be required to have the data. Please remove Part 5.3. If Part 5.3 persists in the next draft, we request that the drafting team provide written justification for why these requirements do not meet P81 criteria and actually materially support reliability. (11) We request that R6 be modified to state that the timeframe shall be mutually agreeable. The TOP is only required to consult with the GO and could still provide an unreasonable timeframe after such consultation. At the very least, the requirement needs to be clear that the GO and GOP are not obligated to take an outage to implement tap changes and would be allowed make them at the next scheduled maintenance or forced outage with sufficiently long outage window to allow such changes. (12) The evidence retention section needs to be updated. First, it covers only measures one through four when there are actually six. Second, it covers measures when it should cover requirements to be consistent with existing standards. (13) As written, the VSL for R1 is overly harsh. If a TOP simply failed to create a single voltage schedule, it would be a severe violation. It seems the VSLs could be graduated based on the number of voltage schedules that are not created as a percentage of the total voltage schedules. (14) The VSLs for R2 and R3 are inconsistent with the requirement. The High VSL and Severe VSL mention avoiding violating an SOL or IROL respectively. However, the requirement mentions neither. This would be inconsistent with FERC guideline three that VSLs should be consistent with the corresponding requirement. (15) The High and Severe VSLs for R2 and R3 overlap with one another. High VSLs for both requirements apply to SOL violations and Severe VSLs for both requirements apply to IROL violations. By definition in the NERC glossary, an IROL is a subset of a SOL. Thus, a failure to schedule or operate reactive resources that results in an IROL violation would be both a High and Severe violation simultaneously. (16) From a compliance perspective, the High VSL for VAR-001-4 R4 is a logical fallacy. Compliance requires evidence. Thus, an auditor cannot make a determination that a TOP has exemption criteria but does not have evidence of exemption criteria. Thus, the High VSL could never be assigned by a

compliance enforcement authority. This needs to be modified. (17) The VSLs for VAR-001-4 R5 need to be modified. In the FERC order approving VSLs, FERC was clear that as many VSLs as possible should be used. Clearly, each VSL could be assigned based on the number of GOPs that the TOP failed to provide voltage schedules. This essentially means that the High VSL should be graduated. We disagree with assigning a moderate VSL for the failure of a TOP to provide its criteria in response to Part 5.3 by one minute. As written, the TOP could literally be one minute past the 30 day time frame and reach a moderate violation. This should not even be a violation let alone a Moderate VSL. The solution is to remove Part 5.3. If Part 5.3 persists, at a minimum, the VSL should be Lower because reliability is not impacted. The second half of the Severe VSL regarding not supplying the notification requirements to the GOP should be moved to Moderate VSL. Failure to provide voltage schedules misses significantly more of the spirit of the requirement than failure to provide exemption criteria. The purpose of failure to provide exemption criteria is an attempt to avoid nuisance violations not directly support reliability. (18) In the regional variances section, E.A. 16 and E.A. 17 meet P81 criteria and should be removed from the next draft. The purpose of these two requirements is to provide transparency between the GOP and TOP in determining voltage schedules and implementation of voltage schedules. While establishing transparency is certainly a laudable goal, it simply does not directly support reliability. Thus, these two regional variance requirements meet Criterion A (overarching) because they do little, if anything, to benefit or protect the reliable operation of the BES and meet criterion B4 – Reporting because they require the TOP and GOP to report to each other. (19) It is unnecessary to require the TOP to direct the Generator Operator to comply with the voltage schedule with the AVR in voltage control mode in VAR-001-4 Part 5.1. It is redundant with VAR-002-3 R2 which compels the GOP to follow the voltage schedule. If drafting team feels the “directive” language is necessary in VAR-001-4 Part 5.1, then VAR-002-3 R2 should be removed because it would be redundant with TOP-001-1a R3 (existing) and TOP-001-2 R1 (pending regulatory approval). Both require the GOP to follow the directives of its TOP.
(1) Consistent with our comment number 9 in question 2, VAR-002-3 R2 and Part 2.1 need to be modified so that the GOP is only required to follow the voltage schedule if provided by the TOP. It is not desirable for the TOP to provide all generators voltage schedules. As an example, the TOP may determine it does not need to provide a voltage schedule to a small generator. To consider this situation, the clause “if a voltage schedule is provided by the TOP” could be added to both Part 2.1 and the main requirement. (2) VAR-002-3 R5 meets multiple P81 criteria and should be removed. It meets Criterion A (overarching) because it does little, if anything, to benefit or protect the reliable operation of the BES and meets B2 – Data Collection/Data Retention and B4 – Reporting because it requires the GOP to gather their tap setting information and report it to a third party (i.e. its TOP) which is unnecessary to implement as a reliability requirements. A GOP is not going to refuse to provide data to its TOP on its generator step up transformer in a compliance driven world. In fact, making this data subject to compliance slows the free exchange of the information because of all the extra checking that goes into managing (i.e. verifying, checking, storing) compliance documentation. This requirement also meets B7 – Redundant because the TOP can specify this data in its data specification per TOP-003-2 R1, distribute to the GO per TOP-003-2 R3 and then GO would

have to respond per TOP-003-2 R5. (3) VAR-002-3 Part 6.1 meets a P81 criterion and should be struck. It meets Criterion A (overarching) because it does little, if anything, to benefit or protect the reliable operation of the BES and meets B4 – Reporting because it requires the GO to report a technical justification for not implementing tap changes. This technical justification simply does not support reliability. The TOP can make adjustments to other voltage schedules to account for the GO's inability to implement the tap changes. What is the purpose of the GO providing the TOP a technical justification? Is it to provide the TOP some assurance there is a technical reason for failing to implement the tap changes? In a compliance driven world, the TOP can reasonably expect the GOP to implement the tap changes unless the changes would violate safety, equipment limits, regulatory or statutory requirements since these only the only deviations allowed by the main requirement. The threat of sanctions assures this. Furthermore, the GOP may legitimately not have a "technical" justification because a regulatory requirement is a legal justification not a technical justification. (4) The RSAW for VAR-002-3 indicates that compliance assessment for R4 could be vague and result in inconsistent outcomes. The RSAW indicates that the auditor will look for evidence when the GOP became aware of changes. If the entity's data historian or another piece of evidence indicates a reactive capability change occurred at a certain time, does this mean that the entity is aware? We think the answer is no. The entity is only aware when its personnel become aware and not when a measurement first records that something is askew. Furthermore, we believe personnel should be limited to the plant operators in the control room who have overall responsibility. Any evidence review for when the entity became aware should be limited to plant operator logs because this evidence will most closely demonstrate what the plant operator knew based on information provided and will not be as likely to be second-guessed on what the plant operator should have known. (5) VAR-002-3 R2 will be problematic for some GOPs because it does not reflect the characteristics of the voltage schedule provided by some TOPs. For example, some TOPs provide an hourly average voltage schedule to avoid the need for notification for every time the GOP drifts out of schedule. How would R2 be applicable in this situation? Would it only apply for the first 15 minutes of each hour looking back at the last hour? Please modify the requirement accordingly to address this issue.
We do not support the VSLs for R5 because it meets P81 criteria and should be removed. We also do not support the VSLs for requirements that need modifications as identified in question 3.
Group
DTE Electric Co.
Kathleen Black
Yes
Yes
Yes Comments: Adding the 15 minute window in VAR-002 is a great improvement.
Individual
Roger Dufresne

Hydro-Québec Production
Yes
No
The requirement number five has to be removed, the reactive power of an auxiliairy transformer unit has a little impact on the ability of a groupe or plant to provide the reactive power required by the network.
Group
ISO/RTO Standards Review Committee
Gregory Campoli
Yes
We support this direction and the SDT's decision to not reiterate or duplicate the voltage assessment requirements already addressed by the FAC and TOP standards.
Yes
We support the SDT's proposal to remove the requirements that may be redundant with other standards. We do not have any comments on the requirements, Measures or VRFs, but we do have some comments on the VSLs: a. R1: The word "schedule" after "system voltage" is missing from the VSL. b. There is inconsistency in the tense used in various VSLs – some are in present tense while others in past tense. Please review and revise as appropriate.
We assess the changes proposed under Q2 and Q 3, above, are not substantive and do not materially change the intent or content of the standards. Therefore, if the standards receives 2/3 majority approval at the ballot, these changes can be implemented and posted for recirculating ballot without having to post and ballot the standards for a successive ballot. We agree with most of the proposed changes, but would suggest the following changes to more effective convey the intent of Requirement R3 and Measure M3. a. R3: The wording "the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator" is not a direct action and may not be measurable. We suggest to revise it to read: "the Generator Owner shall implement the transformer tap positions according to the specifications provided by the Transmission Operator…." b. M3: We suggest it be reworded to require demonstration of compliance rather than to require actions which should have been stipulated in the requirement. Specifically, we proposed the last part in Measure M3 be revised to: "…therefore, if a status change lasts more than 15 minutes, the GOP shall provide evidence such as system log, electronic message or a transmittal letter that it notified its associated Transmission Operator within 30 minutes of when the change first occurred." We further propose that the SDT insert the evidence language into the first sentence of Measure M3 which asks for evidence that the Generator notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3.
We support the proposed VRFs and VSLs.
Individual
Michelle D'Antuono

Ingleside Cogeneration LP
Yes
Yes
Yes,Ingleside Cogeneration agrees that there must be reasonable notification criteria controlled by TOPs that allows them to specify when notification of change in AVR or reactive resource status is necessary. In many cases, the status is telemetered in real-time, but a call is required anyways to specify the expected duration of the status change. This is overcommunication in most cases, and only serves to tie up resources at the GOP and TOP. The same is true of notifications when the GOP cannot maintain the voltage at the interconnection point. Many GOPs do not control interconnection voltage and could actually resist an adjustment that the TOP is trying to make in response to system conditions. Again, some reasonable notification criteria could stop a lot of nuisance calls under these circumstances.
Individual
Scott Langston
City of Tallahassee
Agree
Florida Municipal Power Agency
Group
Santee Cooper
S. Tom Abrams
We agree with the comments of the North American Generator Forum.
Individual
John D. Brockhan
CenterPoint Energy, Houston Electric LLC.
Yes
CenterPoint Energy believes the language proposed in R1 supplemented by the rationale for R1 is clear in stipulating that a Transmission Operator specified voltage schedule must operate within the boundaries of System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs). What is missing from this standard is the coordination that occurs between the Reliability Coordinators, Transmission Operators, and Generator Operators in defining voltage schedules that do not violate established SOLs and IROLs. Transmission Operators have capabilities to monitor, study, and control their systems but do not have the complete data that a Reliability Coordinator uses to establish SOLs and IROLs. Furthermore, the Reliability Coordinator establishes a baseline voltage profile for the Reliability Coordinators area and its Transmission Operators to review before the schedule is finalized, distributed, and posted. CenterPoint Energy believes that Voltage and Reactive standards that apply strictly to the TOP and/or the GOP and GO create a possible misalignment in the operation of the Bulk Electric System. Moving forward with these standards only to address

the RC’s applicability to the monitoring and control of voltage and reactive at a future date would not accurately reflect the industry’s Real-Time operation with respect to voltage and reactive processes and does not align with NERC’s Functional Model definition and relationships of an RC with other Functional Entities. CenterPoint Energy appreciates the efforts of the Standard Drafting Team and recommends the following requirement lanauge to add the Reliability Coordinator back into the applicability of the standard: “Each Transmission Operator shall coordinate with the applicable Reliability Coordinator to 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 any Interconnection Reliability Operating Limits established by the applicable Reliability Coordinator.”
Yes
CenterPoint Energy agrees with the SDT’s efforts to eliminate duplicated standards, but has the following concerns. R1.1 is unclear on the applicability of the “30 days of a request.” Is the requirement for Transmission Operators to provide their perspective Reliability Coordinators the voltage schedule automatically without a request and only to any adjacent Transmission Operators that requests the schedule within 30 days of the request; or is it the intent of the SDT for the Reliability Coordinator to also request the Transmission Operator for the schedule with the same “30 days of request” requirement. In order for a TOP to obtain evidence to prove compliance to this requirement, a TOP must receive documentable requests from its RC and/or its adjacent Transmission Operators to then provide the voltage schedule within the 30 days of the request. If the Transmission Operators do not receive such requests then essentially according to the standard they do not have to provide the established voltage schedules as the requirement currently specifies. Many Reliability Coordinators or regions have established voltage working groups with processes or its equivalence to aid in the corroboration and defining of company specific voltage schedules within the RCs area or region then such voltage schedules would already be provided as part of the regional processes. CenterPoint Energy recommends the following clarifying language: “If requested, Eeach Transmission Operator shall provide, a copy of the voltage schedules and associated tolerance bands to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of such a request.” CenterPoint Energy agrees with providing the Generator Operators the voltage or Reactive Power schedule; however, we believe R5.1, which also requires the Transmission Operator to direct the Generator Operators to comply with such schedule to the specificity that the AVR be in automatic voltage control mode, is redundant and is an unnecessary requirement as well as a compliance burden for the Transmission Operators. Exemptions to the Generator Operator to deviate from the established voltage schedule or the Automatic Voltage Regulator functioning in any mode other than automatic voltage control are addressed in R4 and VAR-002-3 R1 and R2 and will be handled in Real-Time operations and will be scenario specific. VAR-002 R1 and R2 requires Generator Operators to maintain the voltage or Reactive Power schedule and operate each generator with its AVR in service and in the automatic voltage control mode. Based upon this redundancy and Paragraph 81 criteria regarding duplicative and redundant requirements CenterPoint Energy recommends removal of the language “…and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in

service and controlling voltage)".
Yes, CenterPoint Energy agrees with these revisions to VAR-002 removing compliance issues that address burdensome notification requirements, allowing the Transmission Operator, through VAR-001 to tailor notification requirements based on system/area needs.
CenterPoint Energy believes the VSLs associated with VAR-001 R2 and R3 do not consider changes in Real-Time topography such as forced outages, Resource inadequacy, or changes in weather that can drastically change the outcome of any planned or studied environment in both normal and emergency operations. A transmission operator could have scheduled sufficient reactive resources as necessary and have them available to mitigate known and identified SOLs or IROLs, but cannot schedule sufficient reactive resources for the unknown. CenterPoint energy suggests adding "identified" to the VSL language. "The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an identified SOL or IROL". CenterPoint energy believes that the High VSL for R4 is inappropriate and is indicative of a zero tolerance environment. If a Transmission Operator has an exemption criteria established, notifies the Generator Operator of such exemption, and captures evidence for compliance to prove notification 99 times out of 100, then the one instance in which the TOP notified the Generator Operator, but failed to capture evidence would warrant a High VSL possible violation.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC Review Group
Individual
Catherine Wesley
PJM Interconnection
Yes
Yes
PJM recommends the drafting team revise R1 as follows: Each Transmission Operator shall specify a system voltage schedule. The remaining language in that requirement is not needed to support reliability. PJM does not understand the scope of controllable load in R2. We urge the drafting team to include clarification. For R3, PJM recommends revision to the Time Horizon to include Real Time only. PJM recommends the following addition to R5 as the last phrase in the requirement for consistency with R4 language. "unless otherwise exempted as noted in R4."
Yes.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No

Yes
In the draft of VAR-001-4 R2 the use of the word 'schedule' when referring to all reactive resources is unclear. This is in conjunction with the Compliance response to question 2 part 2, "…provide the documentation for the day ahead scheduling in addition to documentation supporting that it was scheduled..." found in the NERC document Draft Reliability Standard Compliance Guidance for VAR-001 and VAR-002 dated July 8, 2013. Is it the ad hoc group's intent to have a schedule for all reactive resources including capacitors, reactors, Static var Compensators and generators? Is the schedule meant to be similar to that of a generator (i.e. Insert capacitors at 1.0pu and remove at 1.05) or on a time base? Is schedule just supposed to take into account availability of all reactive resources? Also TSGT believes the statement "(at either the high or low side of the Generator Step-Up transformer at the TOP's discretion)" currently in VAR-001-4 R4 to should be changed to "(at an agreed upon metering point to which the GOP has direct access)." For VAR-001-4 R6 why did the ad hoc group not change the consultation requirement from GO to GOP? Tri-State believes that this information would better serve the GOP function particularly at Co-Owned facilities. This change would not have a negative effect on the reliability of the BES would reduce duplicative notification to be administered by the TOP.
For VAR-002-3 R5 TSGT believes the TOP should consult with the GOP rather than the GO to better align requirement R5 with its subrequirement R5.1.
Individual
Mary Lou Ideus
EDP Renewables North America LLC
Yes
Yes
Yes. EDPR NA believes it is important for TOPs to have the flexibility to tailor its requirements, as long as there is sufficient coordination among affected entities. We also offer the following comment: VAR-002 R1: We support the concept that a GOP need not notify its TOP that its AVR is out of service if it has previously advised its TOP that it will not have its AVR in service during start-up and shut-down. We recommend that similar provision be made for variable energy resources which are not able to provide voltage support when operating in similar circumstances. Wind farms, for example, generally have equipment limitations that can affect their ability to follow voltage schedules when operating at low levels. Wind farms will not telemeter a different status in that circumstance, however. We propose that, if a variable energy resource has notified its TOP of equipment limitations that affect its ability to follow a voltage schedule until it achieves a certain level of production, also not be required to notify the TOP that its AVR is out of service.
No.
Group
Bonneville Power Administration
Andrea Jessup

Yes
The SDT considered standards put in place after Order 693 was issued and avoided overlapping FAC and TOP standards. The SDT did include the tolerance band requirement to be consistent with voltage limit requirements in other standards.
Yes
There are two questions under Question #2. BPA answered the first question in the check box. BPA's answer to the second part of the question is No.
Yes. Comments: BPA requests further clarification of VAR-002-3 R3 and M3, to be revised such that a status or capability change in generator Reactive Power should be reported within 30 minutes from an entity becoming aware of the change in condition, rather than the current form, which is 30 minutes from the change in condition.
No.
Individual
Brenda Hampton
Luminant Energy Company LLC
Agree
Luminant Generation Company, LLC
Group
Colorado Springs Utilities
Kaleb Brimhall
Agree
Florida Municipal Power Authority

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2013-04 Voltage & Reactive Control

The Project 2013-04 Voltage & Reactive Control Drafting Team thanks all commenters who submitted comments on the draft VAR-001-4 and VAR-002-3 standards. These standards were posted for a 45-day public comment period from October 11, 2013 to November 25, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 58 sets of comments, including comments from approximately 165 different people from approximately 107 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Russel Mountjoy	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madison Gas and Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6

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

10.	Marie Knox	Midcontinent Independent System Operator		2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

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

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

22.	Brian Shanahan	National Grid	NPCC	1
23.	Wayne Sipperly	New York Power Authority	NPCC	5
24.	Ben Wu	Orange and Rockland Utilities	NPCC	1
25.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
26.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Erika Doot	Bureau of Reclamation	X				X					

No Additional Response

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	NERC Compliance Policy	RFC	5, 6
2.	Mike Garton	NERC Compliance Policy	NPCC	5, 6
3.	Randi Heise	NERC Compliance Policy	SERC	1, 3, 5, 6
4.	Michael Crowley	Electric Transmission	SERC	1, 3
5.	Ed Croasdale	Electric Transmission	SERC	1, 3
6.	Chip Humphrey	Power Generation	NPCC	5
7.	Sean Iseminger	Power Generation	SERC	5
8.	Larry Whanger	Power Generation	SERC	5
9.	Jarad Morton	Power Generation	RFC	5
10.	Jeff Bailey	Nuclear		5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				

No Additional Response

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

No Additional Response

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Bob Steiger	Salt River Project	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
No Additional Response													
8.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1

				1	2	3	4	5	6	7	8	9	10
9.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Palmer		SERC	5
2.	Tony Segovia		SERC	5
3.	Tom Vandervort		SERC	5
4.	Lee Thomas		SERC	5
5.	Ian Grant		SERC	3
6.	Marjorie Parsons		SERC	6
7.	DeWayne Scott		SERC	1
8.	Matt Schebler		SERC	1
9.	David Thompson		SERC	5

				1	2	3	4	5	6	7	8	9	10
10.	Group	Ryan Millard	PacifiCorp					X	X				
No Additional Response													
11.	Group	Colby Bellville	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Lloyd A. Linke	Western Area Power Administration	X					X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Western Area Power Administration	Coloratdo River Storage Project	WECC	6
2.	Western Area Power Administration	Rocky Mountain Region	WECC	1, 6
3.	Western Area Power Administration	Sierra Nevada Region	WECC	1, 6
4.	Western Area Power Administration	Desert Southwest Region	WECC	1, 6
5.	Western Area Power Administration	Upper Great Plains Region	MRO	1, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC	RFC	5
3.		PPL Susquehanna, LLC	RFC	5
4.		PPL Montana, LLC	WECC	5
5.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			RFC	6
8.			SERC	6
9.			SPP	6
10.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
3.	Kevin Frick	Westar Energy	SPP	1, 3, 5, 6
4.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
5.	Michael Jacobs	Consolidated Assest Management Services	NA - Not Applicable	NA
6.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
7.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

8. Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
9. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
10. Randy Root	Grand River Dam Authority	SPP	1, 3, 5
11. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
12. Dennis Sauriol	American Electric Power	SPP	1, 3, 5
13. Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
14. Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
15. Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
16. Scott Williams	City Utilities of Springfield	SPP	1, 4

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

Additional Member	Additional Organization	Region	Segment Selection
1. Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2. Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
3. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5. Paul Jackson	Buckeye Power	RFC	3, 4
6. Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
7. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
8. John Shaver	Southwest Transmission Cooperative	WECC	1

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

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

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

Additional Member	Additional Organization	Region	Segment Selection
1. K. Goodman	ISO-NE	NPCC	2
2. B. Li	IESO	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	C. Yeung	SPP	SPP	2									
4.	A. Dicaprio	PJM	RFC	2									
5.	T. Bilke	MISO	RFC	2									
6.	A. Miremadi	CAISO	WECC	2									
18.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Rene Free	Santee Cooper	SERC	1, 3, 5, 6									
2.	Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6									
19.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Steve Hitchens	Technical Operations	WECC	1									
2.	Tanner Brier	Power Services	WECC	1									
20.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
No Additional Response													
21.	Individual	John Canavan	NorthWestern Energy	X									
22.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
23.	Individual	Ronnie C. Hoeinghaus	City of Garland			X							
24.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
25.	Individual	Oliver Burke	Entergy Services, Inc.	X									
26.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
27.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
28.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
29.	Individual	Angela P Gaines	Portland General Electric Co	X		X		X	X				
30.	Individual	Anthony Jablonski	ReliabilityFirst										X
31.	Individual	Bill Fowler	City of Tallahassee			X							
32.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Michael Falvo	Independent Electricity System Operator		X								
34.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
35.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
36.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
37.	Individual	Lynda Kupfer	Puget Sound Energy	X		X		X					
38.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
39.	Individual	Rjick Terrill	Luminant Generation					X					
40.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
41.	Individual	David Jendras	Ameren	X		X		X	X				
42.	Individual	Kathleen Goodman	ISO New England Inc.		X								
43.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
44.	Individual	Robert L. Dintelman	Utility System Efficiencies, Inc.					X					
45.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
46.	Individual	Gerald G Farringer	Consumers Energyu			X							
47.	Individual	Chris Scanlon	Exelon Companies	X		X	X	X	X				
48.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
49.	Individual	Dave Willis	Idaho Power Company	X									
50.	Individual	Roger Dufresne	Hydro-QuÃ©bec Production					X					
51.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
52.	Individual	Scott Langston	City of Tallahassee	X									
53.	Individual	John D. Brockhan	CenterPoint Energy, Houston Electric LLC.	X		X							
54.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
55.	Individual	Catherine Wesley	PJM Interconnection		X								
56.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
57.	Individual	Mary Lou Ideus	EDP Renewables North America LLC					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
58.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				

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

Organization	Agree	Supporting Comments of "Entity Name"
Western Area Power Administration	Agree	US Bureau of Reclamation.
Colorado Springs Utilities	Agree	Florida Municipal Power Authority
Entergy Services, Inc.	Agree	SERC OC Review Group
City of Tallahassee	Agree	FMPA
NextEra Energy	Agree	MidAmerican
ISO New England Inc.	Agree	IRC SRC
City of Tallahassee - Electric Utility	Agree	FMPA
US Army Corps of Engineers	Agree	MRO NSRF
City of Tallahassee	Agree	Florida Municipal Power Agency
South Carolina Electric and Gas	Agree	SERC OC Review Group
Luminant Energy Company LLC	Agree	Luminant Generation Company, LLC

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper		We agree with the comments of the North American Generator Forum.

1. **Although FERC directed NERC to provide more details on "established limits," the VAR standards development team determined that the FAC and TOP standards provide explicit requirements on voltage limits. Further, the definition of a System Operating Limit requires Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits) to be included. Is it clear that the specifics with regard to voltage limits are to be determined and monitored as part of operating within System Operating Limits and Interconnection Reliability Operating Limits?**

Organization	Yes or No	Question 1 Comment
Tri-State Generation and Transmission Association, Inc.	No	
Northeast Power Coordinating Council	Yes	We support the direction being taken and the SDT's decision to not reiterate or duplicate the voltage assessment requirements already addressed by the FAC and TOP standards.
Response: Thank you for your comments. The VAR SDT determined that SOLs and IROLs will cover voltage limits as needed in Order No. 693.		
ISO/RTO Standards Review Committee	Yes	We support this direction and the SDT's decision to not reiterate or duplicate the voltage assessment requirements already addressed by the FAC and TOP standards.
Response: Thank you for your comments.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees it is clear voltage limits are to be monitored as either SOLs or IROLs. However it seems the SDT could make more changes to clear up more items.A. VAR-001 R3 grammatical: recommend deleting "as necessary" from this sentence. It adds no value and is not needed.B. It appears VAR-001 R4 allows the TOP to not comply with the VAR Standards by utilizing exemptions?

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The phrase "as necessary" was retained because several TOPs do not intervene and direct devices unless the other applicable entities have not taken other steps to control voltage as necessary or required by various other standards. The exemptions provide a mechanism for TOPs to give exemptions based on system needs and individual GOP characteristics. R4 provides exemptions for GOPs from: 1) following a schedule; 2) being in voltage control mode; or 3) providing particular notifications. Based on industry input the standards needed specificity on the types of exemptions that a TOP can provide.		
Independent Electricity System Operator	Yes	We support this direction and the SDT's decision to not reiterate or duplicate the voltage assessment requirements already addressed by the FAC and TOP standards.
Response: Thank you for your comments.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	R1: The modifications in this version of VAR-001 R1 are good because they standards that are now enforceable, particularly FAC-011 and FAC-014.M2: All Transmission Operators are required to run contingency analysis on the real time system on a periodic basis per TOP-008-1 R4. We suggest modifying VAR-001 M2 to state: "If the assessment is performed in the Operations Planning Horizon, Transmission Operators shall provide copies of assessments used as the basis for how resources were scheduled." M3: Actions are not always required to be taken because of automatic settings of reactive devices. We suggest modifying VAR-001 M3 to state: "Each Transmission Operator shall have evidence that actions were taken as necessary to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments."R5.3 states, "The Transmission Operator shall provide the criteria used to develop voltage schedules and associated tolerance bands to the Generator Operator within 30 days of receiving a request." We suggest that this requirement is removed due to administrative burden.

Organization	Yes or No	Question 1 Comment
		We recognize the need for transpency; however, this requirement does not serve a reliability purpose.
Response: Thank you for your comments. Since FERC recently proposed remanding the most recent TOP filing, the TOP and VAR interplay will be further evaluated. However, the concerns with regard to TOP-008-1 will be conveyed to Compliance for a future iteration of an RSAW and auditor training. Requirement R5, part 5.3 could not be removed because that specially addresses a FERC directive for VAR-002. Part 5.3 demonstrates who a TOP will provide technically justified schedules.		
Bonneville Power Administration	Yes	The SDT considered standards put in place after Order 693 was issued and avoided overlapping FAC and TOP standards. The SDT did include the tolerance band requirement to be consistent with voltage limit requirements in other standards.
Response: Thank you for your comments.		
SPP Standards Review Group	Yes	We thank the drafting team for taking this stance in not establishing details in the VAR standards and relying on those that already exist within defined SOLs and IROLs. Adding additional detail here would be redundant and possibly conflicting with requirements in other standards.
Response: Thank you for your comments.		
ACES Standards Collaborators	Yes	Yes this is clear. We thank the drafting team for removing the duplication from the previous draft.
Response: Thank you for your comments.		
CenterPoint Energy, Houston Electric LLC.	Yes	CenterPoint Energy believes the language proposed in R1 supplemented by the rationale for R1 is clear in stipulating that a Transmission Operator specified voltage schedule must operate within the boundaries of System Operating Limits (SOLs) and Interconnection Reliability Operating Limits

Organization	Yes or No	Question 1 Comment
		(IROLs). What is missing from this standard is the coordination that occurs between the Reliability Coordinators, Transmission Operators, and Generator Operators in defining voltage schedules that do not violate established SOLs and IROLs. Transmission Operators have capabilities to monitor, study, and control their systems but do not have the complete data that a Reliability Coordinator uses to establish SOLs and IROLs. Furthermore, the Reliability Coordinator establishes a baseline voltage profile for the Reliability Coordinators area and its Transmission Operators to review before the schedule is finalized, distributed, and posted. CenterPoint Energy believes that Voltage and Reactive standards that apply strictly to the TOP and/or the GOP and GO create a possible misalignment in the operation of the Bulk Electric System. Moving forward with these standards only to address the RC's applicability to the monitoring and control of voltage and reactive at a future date would not accurately reflect the industry's Real-Time operation with respect to voltage and reactive processes and does not align with NERC's Functional Model definition and relationships of an RC with other Functional Entities. CenterPoint Energy appreciates the efforts of the Standard Drafting Team and recommends the following requirement lanauge to add the Reliability Coordinator back into the applicability of the standard: "Each Transmission Operator shall coordinate with the applicable Reliability Coordinator to 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 any Interconnection Reliability Operating Limits established by the applicable Reliability Coordinator."

Response: Thank you for your comments. The VAR SDT recognizes the ERCOT roles of the Reliability Coordinator, but it is the VAR SDT's understanding that the coordination between the RC and TOP are handled by registration or contract. Further, the next project addressing the IRO family of standards will address the RC functions.

Organization	Yes or No	Question 1 Comment
Dominion	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Florida Municipal Power Agency	Yes	
Tennessee Valley Authority	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
PPL NERC Registered Affiliates	Yes	
DTE Electric Co.	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Xcel Energy	Yes	
Luminant Generation	Yes	
City of Austin dba Austin Energy	Yes	
Ameren	Yes	
Utility System Efficiencies, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Consumers Energyu	Yes	
Exelon Companies	Yes	
Idaho Power Company	Yes	
Hydro-QuÃ©bec Production	Yes	
Ingleside Cogeneration LP	Yes	
PJM Interconnection	Yes	
EDP Renewables North America LLC	Yes	
Puget Sound Energy		- The implementation period might be as short as one day as the Effective Date section is currently formulated. For example, if approval occurs on 12/31/2013, the first day of the first calendar quarter after that date would be 1/1/2014. A short implemen
Response: Thank you for your comments. For the United States, if the VAR-001 standard passes a final ballot in December, the standard would not be presented to the Board of Trustees until February. It is not until the Board of Trustees approves the standard that the new standards would even be filed with FERC. FERC has not typically issued an order on a standards filing within six months. Therefore, it is unlikely that these VAR standards would even be able to go into effect before April 2014 in the United States.		

2. **Several requirements were removed because they duplicated other standards. Do you agree with this approach? Do you have any specific questions or comments relating to the requirements in the revised VAR-001-4?**

Organization	Yes or No	Question 2 Comment
American Electric Power	No	
Public Service Enterprise Group	No	1. R4 and part 4.1 address generator exemptions. R4 requires TOPs to develop criteria for exempting generators from R5, part 5.1. Those criteria should be made available. However, TOPs, not generators, must comply with R5, part 5.1. If the SDT's intent is to exempt specific generators from following a voltage or Reactive Power schedule, we suggest the following rewrite for R4, with no change to part 4.1:R4. Each Transmission Operator shall specify the generator criteria that will exempt Generator Operators of generators that meet these criteria from compliance with the requirement to maintain a voltage or Reactive Power schedule and publish or provide such criteria upon request.M4 would have to be rewritten, with item 2) and item 3) deleted. Because 1) exempts a generator from having to meet a voltage of Reactive Power Schedule and 2) exempts a generator from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, being exempt from having to meet a voltage schedule in 1) is equivalent to being exempt from 2). Item 3) is addressed by exemptions stated in VAR-002-3, R1 and R2.2. R5, part 5.1 should have the phrase "in automatic voltage control mode (the AVR is in service and controlling voltage)" stricken since it would not apply to a Reactive Power schedule. In addition, the TOP should not be required to provide voltage or Reactive Power schedules to exempt generators under part 5.1. Finally, the text box for R5 refers to maintaining a schedule for "normal operations." "Normal operations" is a critical assumption, which we believe is equivalent to "normal operating conditions." For example, a generator that experiences a fault on its GSU will be outside of any

Organization	Yes or No	Question 2 Comment
		voltage or Reactive Power schedule during that fault. Therefore, part 5.1 should be rewritten:5.1. Except for exempt generators, the Transmission Operator shall provide the voltage or Reactive Power schedule for the associated Generator Operator and direct the Generator Operator to comply with the schedule during normal operating conditions.3. R5, part 5.3 should have the phrase "or Reactive Power" inserted after "voltage."
Response: Thank you for your comments. Exemptions are based solely on the exemption criteria set by the TOP. The language in R4 is broader than the proposed language, and the VAR SDT wanted to provide TOPs with the latitude for providing exemptions as necessary. R4 provides exemptions from: 1) voltage schedules, 2) being in voltage control mode, or 3) any notification requirements. However, an exemption from a schedule does not necessarily equate to an exemption from an AVR setting. Also, since VAR-002 did not pass successive ballot, there is no exemption mechanism in place in VAR-002. Finally, the phrase "or Reactive Power" is being added as clarification to R5.3.		
The United Illuminating Company	No	Please note that my affirmative ballot vote was in error. We are voting NO on VAR-001.Since there is no catchall section for comments on VAR-001, we are providing comments here. Although We do agree with the removal of duplicative requirements, we are voting No on VAR-001.VAR-001 R2 remove everything after the but not limited to phrase. The various methods to obtain reactive power do not belong in the requirement but they can be included in the measure.VAR-001 R3: Clearly this is something a TOP perfroms but the compliance evidence will be overwhelming. The TOP is being asked to demonstrate that it has constantly monitored reactive and provided direction to operate reactive devices. This will require the retention of the evidence of why a reactive adjustment was necessary as well as the various adjustments made. This would mean maintaining snapshots of the normal operation of the system, records of adjustments, corrections, etc.
Response: Thank you for your comments. The draft RSAW clarifies how this requirement would be evaluated during an audit, but the compliance concerns will be conveyed for future iterations of the RSAW and auditor training.		
American Transmission	No	ATC agrees with the approach in removing any duplicate requirements.ATC also has a

Organization	Yes or No	Question 2 Comment
Company, LLC		couple comments and is recommending the following changes for the drafting team to consider:1. For consistency, Measure M2, 2nd sentence should be reworded as follows: “For the operational planning time horizon, Transmission Operators shall “have evidence of assessments” used as the basis for how resources were scheduled” The current wording of “shall provide copies” imposes an action that is not included in the associated requirement R2. 2. The following from requirement R2: “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” implies that all of the items listed need to be considered. If the intent is that the items are intended to be examples it is suggested that the words “including , but not limited to” be replaced by “such as”.
Response: Thank you for your response. M2 will be updated to clarify that TOPs shall have evidence of assessments, rather than provide copies of assessments. The list in R2 was originally added to answer a FERC directive on including controllable load. It was approved in an earlier version of VAR-001, so the SDT retained the same list for R2.		
Ameren	No	We request that the SDT leave the language as currently used in VAR-001-2, R4.
Response: Thank you for your comments. VAR-001-2 R4 does not allow for notifications when deviating from voltage schedules, and the VAR SDT improved on that standard language by requiring the TOP to provide more data such as notifications and criteria for schedules upon request.		
Hydro-QuÃ©bec Production	No	The requirement number five has to be removed, the reactive power of an auxiliairy transformer unit has a little impact on the ability of a groupe or plant to provide the reactive power required by the network.
Response: Thank you for your comments. VAR-002 did not pass the last ballot, and the VAR SDT will consider this during the next successive ballot.		
MRO NSRF	Yes	In requirement 5.1 a Transmission Operator is required direct a Generator Operator

Organization	Yes or No	Question 2 Comment
		to “comply with the schedule” provided by the Transmission Operator. In 5.2, however, the potential for deviations from the schedule is implied. To avoid conflict between these two, the following change to 5.1 is recommended: “The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode unless notification of deviation is provided in accordance with 5.2.”For consistency M2 should be reworded as follows: “For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled” The current wording of “shall provide copies” imposes an action that is not included in the associated requirement. In previous comments regarding voltage schedules issued by a Transmission Operator a mechanism for a Generator Operator to provide explanations if a proposed schedule could not reasonably be met based on specific equipment limitations and to get a revised schedule or exemption was suggested. In this version the Transmission Operator is obligated to provide additional information about the schedule, but is not obligated to respond to Generator Operator concerns regarding the schedule. Under VAR-002 a Generator Operator is required to comply with the schedule provide by the Transmission Operator unless notification is provided. There then is the potential situation where a schedule issued by a Transmission Operator cannot be met due to equipment or system conditions and the only action available is for a Generator Operator to provide multiple notifications. A better solution it seems would be to include some sort of feedback process between Generator Operators and Transmission Operations in the VAR-001 standard that would result in an agreed-upon schedule that could reasonably be met without burdensome periodic notifications. As recommended in previous comments a process of reaching “mutual agreement” on the schedule for making transformer tap changes is suggested . The SDT responded in the consideration of comments that they did not chose to include the suggested agreement language but did add a requirement for the transmission operator to provide an “implementation schedule”. While this change is an improvement it does not completely solve the concern

Organization	Yes or No	Question 2 Comment
		presented. The objective should be that a tap change schedule is agreed upon that would meet the reasonable needs of both the Transmission Operator and Generator Operator. The following from requirement R2: “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” implies that all of the items listed need to be considered. If the intent is that the items are intended to be examples it is suggested that the words “including , but not limited to” be replaced by “such as”.It is recommended that R5.1 be modified as recommended by the NERC IGVT report of September 2012: 5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR or plant-level volt/var regulator is in service and controlling voltage). The standard should be reviewed and where AVR is referred to, the plant-level volt/var regulator should be added in a similar way to this recommended change to R5.1. The referenced NERC report provides the technical basis for this recommendation.
Response: Thank you for your comments. M2 has been modified to incorporate your suggestions. The VAR SDT determined that the mutually-agreed upon schedule could undermine TOP authority, and the VAR SDT also determined that AVR is a sufficiently broad term to encompass plant-level volt/VAR.		
Northeast Power Coordinating Council	Yes	We support the SDT’s proposal to remove the requirements that may be redundant with other standards. However, regarding VAR-001-4 Requirement R1 was revised to read: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 1.1 Each Transmission Operator shall provide a copy of the voltage schedules and asspociated tolerance bands to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.What is meant by “system voltage schedule.” Is it a highâ€ level, overall voltage schedule by voltage class, or a voltage schedule by station (even if there is no direct means of

Organization	Yes or No	Question 2 Comment
		controlling voltage at that station)? Requirement R5 already addresses specification of generator voltage schedules, so if that is what is intended to be addressed under R1, why is R1 needed at all? Requirement R5 states: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.There is inconsistency in the tense used in various VSLs. Some are in present tense while others are in the past tense. This should be reviewed and and revised as appropriate."Schedule" is used in both VAR-001 Requirements R1 and R5. However, it is modified by different phrases in each, implying different types of "schedules." These two different types of "schedules" have caused confusion, making the use and intended meaning less than perfectly clear. VAR-001 Requirement R1 - To improve clarity and consistency, suggest that the word "schedule" be deleted here and only be used when referring to GOP operation. Suggest revising Requirement R1 wording as follows:R1. Each Transmission Operator shall specify a system voltage 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.Note that Requirement R1 only requires that the TOP establish the target system voltage level and tolerance band. There is no mention of GOP operation.Requirement R2 requires that the TOP schedule its arrangement of sufficient reactive resources, whether actually used (dispatched) or not, a Planning function (see Measure M2). The Rationale box states: "to ensuring sufficient reactive resources are online or scheduled." The use of the word "scheduled" here again has caused confusion. We suggest it be replaced to clarify the meaning, as follows: R2. Each Transmission Operator shall make arrangements for sufficient on-line, available 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, making arrangements for reactive generation resources, transmission line and reactive resource switching, and using controllable load. Further recommend revising M2 to synchronize it with the revised

Organization	Yes or No	Question 2 Comment
		Requirement R2 above, as follows:M2. Each Transmission Operator shall have evidence of sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall provide copies of assessments used as the basis for determining how resources were made available. Organizationally, R4 should be swapped with R5. A requirement dealing with exemptions should come after the “foundation” requirement.The Drafting Team must consider the following regarding Hydro-Quebec TransEnergie. "Schedule" in the standard is confusing and does not apply to Hydro-QuÃ©bec TransÃ‰nergie. Hydro-Quebec TransEnergie does not issue a schedule of voltage or reactive power. Hydro-Quebec TransEnergie sets voltage ranges to comply at all times for the different voltage levels. During light or peak load, these operating situations are governed with voltage setupoints for specific substations. The standard should therefore consider (in addition to the preceding comments) the terms used. For example, consider substituting the term " voltage or reactive power setpoint " for the word “schedule” which does not reflect our operating procedures.Regarding Requirement R5, NERC now requires a specified program voltage or reactive power be given to central planning and forecasting. This requirement is not applicable to Hydro-QuÃ©bec TransÃ‰nergie because there is no voltage or reactive power schedule, but rather the requirement that every generating facility of more than 10 MW have an automatic voltage regulation system. Hydro-Quebec TransEnergie also requires them to provide a specific power factor for each of those generating units.
Response: Thank you for your comments. Requirement R1 is the overarching system voltage schedule, and Requirement R5 targets generating voltage schedule. The requirement does not require a schedule for a station with no way of controlling voltage. Voltage schedule is an industry term that is explicitly defined by the parenthetical definition. The VAR SDT could not make the proposed Requirement R2 changes because it could cause clarification for some while causing confusion for other industry members. Requirements R4 and R5 stand independently. Finally, for R5 the VAR SDT determined that the term “schedule” is broad enough to encompass Hydro Quebec’s concerns.		
Bureau of Reclamation	Yes	The Bureau of Reclamation (Reclamation) notes that the WECC variance indicates that it is intended to replace requirements R3 and R4. However, R3 and R4 in VAR-

Organization	Yes or No	Question 2 Comment
		001-4 are not the same as R3 and R4 in VAR-001-3. Reclamation suggests that the drafting team should examine the WECC variance to determine which requirements it will replace because it appears that the WECC variance should replace R4 and R5. In WECC, it would be difficult for Transmission Operators to comply with both R5 and E.A. 14 because they refer to different voltage schedule reference points. VAR-001-4 R3 specifies that Transmission Operators must operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. Measure M3 specifies that "this may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments." Reclamation suggests that this detail should be included in Requirement R3 rather than solely in the measure.VAR-001-4 R4 requires a Transmission Operator to notify a Generator Operator if the "Transmission Operator determines that a generator has satisfied exemption criteria" but does not specify a timeframe for this notification. Reclamation suggests that the drafting team update VAR-001-4 R4 to specify that the Transmission Operator must notify the Generator Operator within 30 days if the Transmission Operator determines that a generator has satisfied criteria for exemption from voltage or Reactive Power requirements and associated notification requirements. Reclamation also suggests that R4 on exemptions should follow R5 on voltage or Reactive Power scheduling and notification criteria. VAR-001 R5 allows the Transmission Operator to specify a voltage or Reactive Power schedule at either the high voltage side or low voltage side of the Generator Step Up transformer. Reclamation suggests that like in requirement E.A.14, Transmission Operators should be able to specify the voltage schedule at the generator terminals, high side of the generator step-up transformer, point of interconnection, or a location designated by mutual agreement. VAR-001 R5.2 specifies that "The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule." M5 regarding part 5.2 specifies that voice recordings may be used to establish compliance with this requirement. Reclamation suggests that voice recordings should be removed from the list in M5 for part 5.2 because notification

Organization	Yes or No	Question 2 Comment
		requirements established in the planning horizon should be transmitted in writing. Reclamation notes that there is a potential inconsistency between the Transmission Operator notification requirements discussed in VAR-001 R5.2 and the Generator Operator notification requirements discussed VAR-002 R3 and R4. Reclamation recommends that VAR-001 R5.2 be modified to solely address planning horizon notifications. For consistency with the Generator Operator real-time notification requirements established in VAR-002 R3 and R4, Reclamation also recommends that VAR-001-4 R5 should include an additional subrequirement which specifies that the "TOP shall develop real-time notification requirements for the deviations from the voltage of Reactive Power schedule within 30 minutes of when a Generator Operator becomes aware of a change in reactive capability, AVR status, power system stabilizer status, or alternative voltage controlling device status, unless the status is restored within 15 minutes." VAR-001-4 R5 requires the Transmission Operator to specify a voltage or Reactive Power schedule "at either the high voltage side or low voltage side of the Generator Step-Up transformer." VAR-002-3 R2.3 allows Generator Operators to monitor voltages at another location so long as the Generator Operator has a "methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator." Reclamation suggests that having the Transmission Operator and Generator Operator monitor voltages at different locations could lead to confusion in real-time communications. Reclamation suggests that VAR-001-4 R5 be updated to require the Transmission Operator to set voltages based on common monitoring locations to avoid confusion in real-time communications between Transmission Operators and Generator Operators.Reclamation suggests that R6 should be updated to specify that the Transmission Operator must coordinate outages to accommodate required step-up transformer tap changes. Reclamation suggests the drafting team update the requirement to read "After consultation with the Generator Owner regarding necessary step-up transformer tap changes, associated outages, and the implementation schedule...". Reclamation also notes that "Generator Step-Up transformer" is sometimes capitalized in the standard. However, it is not capitalized

Organization	Yes or No	Question 2 Comment
		in the WECC variance or NERC Glossary. Reclamation suggests that the drafting team remove capitalization in the term "Generator Step-Up transformer" because it is not defined in the NERC Glossary.
Response: Thank you for your comments. WECC has a separate process for its regional variance, and WECC will revisit the variance as needed. The measure language does not belong in the standard because it is not an exhaustive list, and it serves as an example for what an auditor should look for in evaluating the requirement. The notifications for exemption are not specified because there may be instances where a GOP receives pre-authorized exemptions. For example, a TOP may specify instances where a GOP does not have to notify the TOP through a pre-approved process. The WECC variance will remain intact, but the variance could not be adopted continent-wide because there was no industry consensus on how to provide the schedule. The language for M5 has been updated to remove the list of evidence because it is not a comprehensive list of all communications. The VAR SDT determined that the GOP must make notifications to the TOP of reactive capability changes, and the deviations are not necessary in VAR-001. The VAR standard cannot add a mutually agreed upon reference point because several GOPs and TOPs can reach a consensus on the mutually agreed upon point. The VAR-002 issues will be addressed in the next successive ballots.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	: The High VSL for VAR-001 R4 should be changed from the proposed state to "The TOP has exemption criteria, but did not notify the GOP." As it is currently written, the TOP satisfied R4, but simply cannot show documentation to prove the satisfaction. The proposed change wording focuses on the TOP not satisfying the requirement. The first clause in the Severe VSL for VAR-001 R5 should be corrected to state "voltage or Reactive Power schedules." In addition, the Severe VSL for VAR-001 R5 should have another OR clause to include the failure to comply with R5.3.
Response: Thank you for your comments. The VAR SDT did not agree on all changes for the VSLs at this time, but a failure to comply with R5.3 is already in the moderate VSL category.		
Florida Municipal Power Agency	Yes	FMPA appreciates the efforts of the SDT to remove some of the duplicative requirements of the VAR standards with other standards (e.g., TOP and FAC

Organization	Yes or No	Question 2 Comment
		standards). However, FMPA is voting Negative because we believe more requirements ought to be treated in the same fashion as described in our earlier comments on the September posting, as provided in a mapping document submitted directly the the SDT to better illustrate those duplications, and as summarized below.VAR-001-4 R2 is duplicative of the requirements of TOPs to plan for and operate to SOLs in the TOP and FAC standards. In order to plan to and operate to SOLs, TOPs must schedule sufficient reactive resources, or they will violate those requirements (just as must-run generators need to be scheduled, yet those are not discussed within the standards). Operating to SOLs is results based, VAR-001-4 R2 is not. VAR-001-4 R2 ought to be deleted.VAR-001-4 R3 is duplicative of requirements of TOPs to plan for and operate to SOLs as described above. As far as TOPs ability to direct, that is covered in TOP-001. VAR-001-4 R3 should be deleted.Although FMPA supports both VAR-001-4 R1 and R5, we wonder if there is some duplication between those requirements and whether they can be combined into a single requirement.
Response: Thank you for your comments. However, the recent TOP standards are remanded by FERC and are being reevaluated generally. The standard cannot rely on implied processes in other standards that are currently in development. R2 and R3 are very specific to voltage requirements which are necessary for the reliable operation of the grid. R1 and R5 are not duplicative because R1 addresses an overall system voltage, and R5 is where TOPs provide a schedule for Generator Operators to maintain.		
Tennessee Valley Authority	Yes	The SDT is requested to clarify the word “directions” as used in M3. The word “directions” is close to, but not, the word “directive” which has a very specific meaning. If the intent is to capture directives, then the word directives should be used. If the intent is to capture communications that are not directives, then the word “directions” should be replaced with wording that is not so close to the word “directives.”Current M3 draft language: M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments. The SDT is requested to consider a modification to R4:Current R4 draft language: R4. The Transmission Operator shall specify the criteria that will exempt

Organization	Yes or No	Question 2 Comment
		generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements. Suggested modification to R4: R4. The Transmission Operator shall specify the criteria, ADD: “if any” that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements.
Response: Thank you for your comments. M3 has been updated to use the word “instructions” instead of “directions.” The standard provides each TOP with the flexibility to determine its own exemption criteria and does not mandate that a TOP issue exemptions.		
PacifiCorp	Yes	PacifiCorp supports MidAmerican's comments.
Duke Energy	Yes	Duke Energy approves of the approach of removing duplicative requirements based on other standards.Duke Energy seeks clarification on the definition of “system voltage schedule” and believes that once this is more clearly defined, it should be added to the NERC Glossary of Terms.The Rationale for Requirement 1 discusses the TOP setting voltage or Reactive Power schedules with associated tolerance bands. However, Requirement 1 makes no mention of using Reactive Power schedules. Is the use of Reactive Power Schedules implied in Requirement 1?Duke Energy suggests changing “Each Transmission Operator shall schedule” to “Each Transmission Operator shall maintain” in Requirement 2 for more clarity. In Duke Energy’s opinion, not all reactive resources can be “scheduled” in order to regulate voltage levels. For example, SVCs cannot be scheduled, the reactive resources of an SVC dynamically change to maintain set voltage levels. The TOP needs to ensure that adequate static and dynamic reactive resources are availble to the System Operator in real time to support the Reliability needs of the BES. Reliability Studies are performed in the Operations Planning horizon to ensure that reactive resources are adequate to support the planned BES configuration.
Response: Thank you for your comments. Requirement R1 requires an overarching system voltage schedule, and TOPs do not set Reactive Power schedules for the system. Requirement R5 is the requirement directed towards Generator Operators where a		

Organization	Yes or No	Question 2 Comment
voltage schedule or a Reactive Power schedule is maintained. The VAR SDT cannot come to a consensus that "maintain" will alleviate compliance issues with regard to specific equipment being available to address voltage levels.		
SPP Standards Review Group	Yes	We agree with the retirement of redundant requirements and suggest that the drafting team delete R2 and R3 in addition to the other deletions already proposed. R2 is redundant with the pending TOP-002-3, R1. R3 is redundant with pending TOP-001-2, R7 and R9.
Response: Thank you for your comments, but Requirements R2 and R3 cannot be deleted because they are specific to voltage and reactive flows.		
ACES Standards Collaborators	Yes	(1) Requirement VAR-001-4 R1 is vague and ambiguous and may be duplicative of VAR-001-4 R5. It requirements need further refinement. First, it states that the TOP shall specify "a system voltage schedule". This is singular. A system always has multiple schedules for generators, capacitor banks, reactors, etc. It does not have a single voltage schedule. Second, what equipment or facilities is the voltage schedule supposed to apply? Is this supposed to be the voltage schedule for a generator? Is this supposed to the voltage for reactor or capacitor switching? Is this supposed to be the voltage limits on a transmission bus? Schedule would tend to imply a level of control and, thus, not a limit but the simple reality is that the requirement is vague, ambiguous, and unenforceable as written. Third, if the requirement applies to voltage schedules at generators, it is duplicative to VAR-001-4 R5 because this already compels the TOP to provide voltage schedules for generators. Please provide additional clarifications in the requirement. (2) We appreciate the drafting team removing duplicate requirements. This version of the standard has been improved greatly. However, we still believe there is some duplication that needs to be addressed. For example, VAR-001-4 R1 requires a TOP to "specify a system voltage schedule... as part of its plan to operate with System Operating Limits and Interconnection Reliability Operating Limits" while VAR-001-4 R2 requires the TOP to "schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions". How does a TOP specify a voltage schedule per R1 and not

Organization	Yes or No	Question 2 Comment
		also schedule sufficient reactive resources per R2? The TOP can't maintain the voltage schedule without scheduling sufficient reactive resources. Please eliminate the duplication. (3) VAR-001-4 R2 is also duplicative of VAR-001-4 R3. R2 requires the TOP to "schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions" while R3 requires the TOP "to operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow". How does the TOP schedule sufficient reactive resources without regulating transmission voltage and reactive flow? The TOP would be operating the voltage-regulation devices when they schedule sufficient reactive resources since the voltage-regulation devices are reactive resources. If the purpose was to delineate by time frames implied by the use of "Real-time Operation" in R3 and "schedule" in R2, the requirements need further refinement to be clear that the targeted time frames are supposed to be different. Furthermore, the Time Horizons for both R2 and R3 are duplicate covering Real-time Operations, Same-day Operations, and Operational Planning which would imply that different time frames are not intended. Please eliminate the duplication or clarify the time frames as appropriate. Detailed application guidelines would help eliminate some of the confusion. (4) Part 1.1 meets P81 criteria and should be retired. The requirement meets Criterion A (overarching) because it "does little, if anything, to benefit or protect the reliable operation of the BES" and meets criterion B4 - Reporting because it requires the TOP to report to another party and has "no discernible impact on promoting the reliable operation of the BES." The mere fact that Part 1.1 only requires reporting upon receiving a request is supportive that it has no impact on reliability. If it did materially support reliability, the RC would be required to have the data and the TOP would be obligated to provide it. Please remove Part 1.1. If Part 1.1. persists in the next draft, we request that the drafting team provide written justification for why these requirements do not meet P81 criteria and actually materially support reliability.(5) Measure VAR-001-4 M2 is inconsistent with the main requirement R2 and needs to be modified. M2 proposed that the TOP shall have evidence of scheduling resources based on their system assessment. While we agree this is likely

Organization	Yes or No	Question 2 Comment
		the method the TOP will use to schedule resources, the simple fact is that it is not part of the requirement and cannot be compelled in the measure. Please modify the measure to be consistent with the requirement. (6) The second sentence of R2 is an explanation and not a requirement. Thus, it should be moved to the application guidelines section. We understand that FERC previously directed NERC to include use of controllable load as a reactive resource because it was not one of the explicitly listed reactive resources. FERC likely included this statement as evidenced by the first sentence of paragraph 1879 of Order 693 to further a policy goal of expanding the use of demand side management (DSM). At the time the order was issued, DSM was in its infancy. Today, DSM has become ubiquitous as demonstrated by the almost 40,000 MW reported in the NERC 2013 Summer Assessment. Given that all organized markets include at least one DSM product, its proliferation will only continue. Thus, the policy goal has been clearly met and specific mention in NERC standards in no longer necessary. In fact, an equally efficient and effective alternative would be to eliminate specific references of any type of reactive resource by striking the second sentence in its entirety. (7) The Time Horizons for VAR-001-4 R3 are inconsistent with the requirement. R3 specifically states that it deals with Real-time operation. Thus, how could Operational Planning and Same-day Operation be applicable? These timelines are conflicting and need to be modified.(8) For requirement VAR-001-4 R4, why can't the GOP make a self-determination that it meets the TOP criteria? Is the TOP obligated to make a determination or to simply supply the criteria to the GOP? The RSAW indicates that the auditor will not determine if the GOP received pre-authorization from the TOP. Thus, the requirement should either be modified so that audit practices will have to be modified or aligned with how the RSAW indicates compliance will be assessed. We recommend that the drafting team work with NERC compliance to align the requirement with the RSAW language.(9) VAR-001-4 R5 should be modified to clarify that the TOP is not required to provide a voltage schedule to all generators but only to those generators that it determines it needs to provide reactive supply. A TOP may determine that a generator is too small to control voltage at its location and that it does not need to provide a voltage schedule

Organization	Yes or No	Question 2 Comment
		for this generator. Including all generators is unnecessary for reliability.(10) Part 5.3 meets a P81 criterion and should be retired. The requirement meets Criterion A (overarching) because it “does little, if anything, to benefit or protect the reliable operation of the BES” and meets criterion B4 - Reporting because it requires the TOP to report its criteria to another party and has “no discernible impact on promoting the reliable operation of the BES.” The mere fact that Part 5.3 only requires reporting upon receiving a request is supportive that it has no impact on reliability. If it did support reliability, the GOP would be required to have the data. Please remove Part 5.3. If Part 5.3 persists in the next draft, we request that the drafting team provide written justification for why these requirements do not meet P81 criteria and actually materially support reliability.(11) We request that R6 be modified to state that the timeframe shall be mutually agreeable. The TOP is only required to consult with the GO and could still provide an unreasonable timeframe after such consultation. At the very least, the requirement needs to be clear that the GO and GOP are not obligated to take an outage to implement tap changes and would be allowed make them at the next scheduled maintenance or forced outage with sufficiently long outage window to allow such changes. (12) The evidence retention section needs to be updated. First, it covers only measures one through four when there are actually six. Second, it covers measures when it should cover requirements to be consistent with existing standards. (13) As written, the VSL for R1 is overly harsh. If a TOP simply failed to create a single voltage schedule, it would be a severe violation. It seems the VSLs could be graduated based on the number of voltage schedules that are not created as a percentage of the total voltage schedules.(14) The VSLs for R2 and R3 are inconsistent with the requirement. The High VSL and Severe VSL mention avoiding violating an SOL or IROL respectively. However, the requirement mentions neither. This would be inconsistent with FERC guideline three that VSLs should be consistent with the corresponding requirement. (15) The High and Severe VSLs for R2 and R3 overlap with one another. High VSLs for both requirements apply to SOL violations and Severe VSLs for both requirements apply to IROL violations. By definition in the NERC glossary, an IROL is a subset of a SOL. Thus, a failure to schedule or operate

Organization	Yes or No	Question 2 Comment
		reactive resources that results in an IROL violation would be both a High and Severe violation simultaneously. (16) From a compliance perspective, the High VSL for VAR-001-4 R4 is a logical fallacy. Compliance requires evidence. Thus, an auditor cannot make a determination that a TOP has exemption criteria but does not have evidence of exemption criteria. Thus, the High VSL could never be assigned by a compliance enforcement authority. This needs to be modified.(17) The VSLs for VAR-001-4 R5 need to be modified. In the FERC order approving VSLs, FERC was clear that as many VSLs as possible should be used. Clearly, each VSL could be assigned based on the number of GOPs that the TOP failed to provide voltage schedules. This essentially means that the High VSL should be graduated. We disagree with assigning a moderate VSL for the failure of a TOP to provide its criteria in response to Part 5.3 by one minute. As written, the TOP could literally be one minute past the 30 day time frame and reach a moderate violation. This should not even be a violation let alone a Moderate VSL. The solution is to remove Part 5.3. If Part 5.3 persists, at a minimum, the VSL should be Lower because reliability is not impacted. The second half of the Severe VSL regarding not supplying the notification requirements to the GOP should be moved to Moderate VSL. Failure to provide voltage schedules misses significantly more of the spirit of the requirement than failure to provide exemption criteria. The purpose of failure to provide exemption criteria is an attempt to avoid nuisance violations not directly support reliability. (18) In the regional variances section, E.A. 16 and E.A. 17 meet P81 criteria and should be removed from the next draft. The purpose of these two requirements is to provide transparency between the GOP and TOP in determining voltage schedules and implementation of voltage schedules. While establishing transparency is certainly a laudable goal, it simply does not directly support reliability. Thus, these two regional variance requirements meet Criterion A (overarching) because they do little, if anything, to benefit or protect the reliable operation of the BES and meet criterion B4 - Reporting because they require the TOP and GOP to report to each other. (19) It is unnecessary to require the TOP to direct the Generator Operator to comply with the voltage schedule with the AVR in voltage control mode in VAR-001-4 Part 5.1. It is redundant with VAR-002-3 R2 which

Organization	Yes or No	Question 2 Comment
		compels the GOP to follow the voltage schedule. If drafting team feels the "directive" language is necessary in VAR-001-4 Part 5.1, then VAR-002-3 R2 should be removed because it would be redundant with TOP-001-1a R3 (existing) and TOP-001-2 R1 (pending regulatory approval). Both require the GOP to follow the directives of its TOP.
Response: Thank you for your comments. Requirement R1 is intended to be the requirement addressing an overarching system schedule, and R5 is directed to the schedules provided to the GOPs. Requirements R1, R2, and R3 are separate requirements where R1 sets a voltage schedule for the system. R2 and R3 represent the actual action a TOP will take to meet voltage requirements. Further, R1 is part of the operational planning horizon, while R2 and R3 include real-time and same day operations. Part 1.1 requires vital information to be shared between entities, and this is particularly important to have accurate studies with regard to interface facilities. M5 has been updated to remove "provide copy." Controllable Load was added per a FERC directive, and the VAR SDT does not believe that it should be removed through an equally effective and efficient manner. The second sentence in R2 is meant as an illustration. For the time horizon, Real-time events may bleed into next-day or longer operations. Directives may extend from the Operational Planning Horizon into the current-day. For reliability purposes, it would not be reasonable for the GOP to grant its own exemptions. All generators must follow a voltage or Reactive Power schedule. Part 5.3 provides the technical justification for a voltage schedule which answers a FERC directive. The TOP must set notifications and timeframes in order to prevent disputes between TOP and GOPs. The VAR SDT discussed this at length, and the VAR SDT determined "consult" was the appropriate word for making tap changes. The evidence retention section has been modified. Compliance will be provided a copy of these comments. The VSLs reflect the SOL and IROLs because those are the system events that would precipitate a TOP action. The VSLs for Requirements R2 and R3 refer to SOL and IROL violations because the purpose of requiring TOPs to "schedule sufficient reactive" and "operate or direct the Real-time operation of devices" is to avoid violations of SOLs and IROLs. As provided in Requirement R1, TOPs must specify a system voltage schedule to ensure that the system is operated within System Operating Limits and Interconnection Reliability Operating Limits, as required under the FAC and TOP standards. Thus, the VAR SDT did not determine a severity level is necessary for anything except an SOL or IROL violation. For all of the requirements the VRF determines the risk to the system while the VSL determines how a requirement is violated. For R4, the VRF is lower, but the violation is still high because a part of the requirement has been violated. WECC will determine if any updates should be made to the WECC variance. For part 5.1, VAR-001 represents the TOP obligations, and VAR-002 has a sister requirement that represents the GOP obligations.		

Organization	Yes or No	Question 2 Comment
ISO/RTO Standards Review Committee	Yes	We support the SDT's proposal to remove the requirements that may be redundant with other standards. We do not have any comments on the requirements, Measures or VRFs, but we do have some comments on the VSLs:a. R1: The word "schedule" after "system voltage" is missing from the VSL.b. There is inconsistency in the tense used in various VSLs - some are in present tense while others in past tense. Please review and revise as appropriate.
Response: Thank you for your comments. The VSLs have been reviewed and corrected to be in the same tense.		
Bonneville Power Administration	Yes	There are two questions under Question #2. BPA answered the first question in the check box. BPA's answer to the second part of the question is No.
Response: Thank you for your comments.		
NorthWestern Energy	Yes	For R2, M2 - It would be very helpful if "their assessments of the system" be clearly defined. For example, would TPL studies suffice as evidence for meeting this requirement or is this more of a real time requirement and if so, what types of evidence is NERC lokking for.
Response: Thank you for your support. TPL studies are part of a different time horizon than Requirement R1. Assessments may take several forms depending on the internal structure of the entity. Also the measure for this requirement will no longer include copies of the assessments.		
Consolidated Edison Co. of NY, Inc.	Yes	The drafting team used the word "schedule" in both VAR-001 Requirements R1 and R5. However, it is modified by different phrases in each, implying different types of "schedules." These two different types of "schedules" has caused confusion, making the use and intended meaning less than perfectly clear. VAR-001 Requirement R1 - To improve clarity and consistency, we recommend that the word "schedule" be deleted here and only be used when referring to GOP operation. The revised Requirement R1 wording recommended follows:R1. Each Transmission Operator shall specify a system voltage [delete: schedule (which is either a] range or a target value with an

Organization	Yes or No	Question 2 Comment
		associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.Note that Requirement R1 only requires that the TOP establish the target system voltage level and tolerance band. There is no mention of GOP operation.Requirement R2 requires that the TOP document its arrangement of sufficient reactive resources, whether actually used (dispatched) or not, a Planning function (see Measure M2). The Rationale box states: “to ensuring sufficient reactive resources are online or scheduled.” Comment: The use of the word “scheduled” here again has caused confusion. We recommend it be replaced to clarify the meaning, as follows: R2. Each Transmission Operator shall make arrangement for [delete: schedule] sufficient on-line, available 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, making arrangements for reactive generation resources [delete: scheduling], transmission line and reactive resource switching, and using controllable load. We further recommend revising M2 to synchronize it with the revised Requirement R2 above, as follows:M2. Each Transmission Operator shall have evidence of [delete: scheduling]sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall provide copies of assessments used as the basis for determining how resources were [delete: scheduled] made available. The verbiage of R4 should come after R5 is stated. From an organizational perspective, a requirement paragraph on exemptions should come after the referenced requirement.
Response: Thank you for your comments. Please see the response to NPCC above.		
City of Garland	Yes	1st question: Yes - we agree with this approach2nd question: We have comments on R2. In ERCOT, the TOP can only plan to respond to voltage issues with the resources they have available. They do not have authority to order generation on line for voltage support nor do they have authority to back down fully loaded generation for voltage support. Only the RC has this authority.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. Please see the responses to ERCOT and CenterPoint above.		
Manitoba Hydro	Yes	(1) M1 - the language in the second paragraph re: Part 1.1 does not match the language of the requirement itself in that the measure refers only to voltage schedules, not voltage schedules 'and associated tolerance bands'. (2) R3 - without further clarification, 'as necessary' will be interpreted to mean as deemed necessary by the Transmission Operator. (3) M3 - the measure in this part contains more details and is more narrow than the requirement itself. The requirement refers to the operation of 'devices to regulate transmission voltage and reactive flow' while the measure refers to the operation of 'capacitive and inductive resources'. Language should be consistent. (4) R4 - the language goes back and forth between 'generators' and 'generating units' - this should be made consistent. Also, the reference to 'associated notification requirements' presumably refers to the associated notification requirements in R5 but this is not specified. (5) M4 - the qualification language that it refers only to generating units 'in its area' appears only in the measure and not in Part 4.1 itself. (6) R5 - neither Generator nor Step-Up is a defined term so they should not be capitalized. (7) M5 - there is a shift in language here. Generally the measures indicate that the responsible entity 'shall have evidence' and that the evidence 'may include'. In this measure, the language is that the responsible entity 'shall have evidence' and that the evidence 'shall include'. This is much more restrictive and may make compliance more difficult as there is no longer flexibility in the evidence that will meet the criteria of the measure. (8) Compliance, Evidence Retention 1.2 - Measures 5 and 6 are not mentioned. (9) Compliance, Compliance Monitoring, 1.3 - The language refers specifically to processes found in the NERC Rules of Procedure. Generally in draft standards, there is just a list of processes that may be used. The reference included in this draft standard is concerning because MB Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure. (10) VSLs, R4 - the words 'of the Generator Operator' are missing from the end of this section. (11) VSLs, R5 - the words 'and associated tolerance bands' is missing from Moderate VSL after 'voltage

Organization	Yes or No	Question 2 Comment
		schedules' and is not fully referenced in Severe VSL.(12) VSLs, R6 - the words 'Documentation specifying requiring tap changes was provided to the Generator Owner but' could be inserted at the start of each of the Lower VSL and Severe VSL.
Response: Thank you for your comments. Some clarifying language has been added to the VSLs. The measurement for M3 is an example of the type of information that can be provided and does not limit the breadth of the requirement. For R4 the associated notifications are specified because they are also used in VAR-002. The capitalization of generator step up in R5 has been corrected, in addition to the M5. Data retention has been changed to include all of the measures. Compliance Monitoring language has removed a reference to the Rules of Procedures. The VSLs have been updated to include "to the generator operator" and to include the definition of voltage or Reactive Power schedules.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees that duplicative requirements should be removed. However, the standard would benefit from additional revisions.A. R1 and R5 should be merged. This could be accomplished in the following manner: "Each Transmission Operator shall notify associated RCs and adjacent TOPs, and specify assigned GOs the a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan required forassigned GOs to operate within System Operating Limits and Interconnection Reliability Operating Limits.B. The second sentence of VAR-001 R2 is not needed. This is not an actionable requirement, but rather is an instruction as to how it's to be done. The 2nd sentence is not a requirement.C. Recommend deleting from R5.1 the words, "...in automatic voltage control mode (the AVR is in service and controlling voltage)." The standard should establish what needs to be done, and how the GO elects to comply with the requirement should be left to the discretion of the GO. Furthermore, VAR-002 requires the GO to have its AVR in service and in auto, so this requirement is also redundant.D. It appears that VAR-001 R6 is redundant to R5.3. Also see comments on VAR-002 R6.
Response: Thank you for your comments. The VAR SDT consensus was to leave Requirements R1 and R5 as separate requirements. R1 sets for requirements for the overarching system voltage while R5 specifies schedules for control buses. The second sentence is meant as an illustration. The VAR SDT and NERC staff determined that the AVR operation in the voltage		

Organization	Yes or No	Question 2 Comment
control mode is necessary for system reliability.		
Independent Electricity System Operator	Yes	We support the SDT's proposal to remove the requirements that may be redundant with other standards. We do not have any comments on the requirements, Measures or VRFs, but we do have some comments on the VSLs:a. R1: The word "schedule" after "system voltage" is missing from the VSL.b. There is inconsistency in the tense used in various VSLs - some are in present tense while others in past tense. Please review and revise as appropriate.
Response: Thank you for your comments. The VSLs have been modified to clarify language and correct the differences in tense.		
Kansas City Power & Light	Yes	I agree with the approach to condense standards if they are duplicated in other standards.
Response: Thank you for your comments.		
Xcel Energy	Yes	Xcel Energy appreciates the hard work of the Standard Drafting Team. We recognize that significant effort has been put into the modifications of the VAR-001 and VAR-002 standards and we applaud the direction the team is moving. We are voting Negative on VAR-001-4 for one reason which we explain below.Xcel Energy believes that the WECC Regional Variance should not replace R4 in the NERC standard based on the rationale provided for modifications to the proposed R4. Instead, WECC Regional Variance Requirement E.A.13 should be removed and the remaining Regional Variance Requirements should supplement the NERC Requirements in the Western Interconnection. As proposed, the NERC standard states that the TOP is not bound to provide a voltage schedule for each BES generator; however , due to the WECC variance, the TOP would be found in violation if any BES Generator was not provided a voltage schedule. In order to resolve the issue, Xcel Energy asks the drafting team to delete E.A.13 in its entirety and modify the language of the Regional Variance to state that the additional requirements are for in addition to the NERC requirements. Once this modification is made, Xcel Energy could support the

Organization	Yes or No	Question 2 Comment
		proposed standard.
Response: Thank you for your comments. The regional variance must be addressed through WECC. WECC will determine if the variance should be updated accordingly.		
Puget Sound Energy	Yes	- The first paragraph of the Regional Variance section of VAR-001 should be updated to reflect that requirements R3 and R4 of the current standard are requirements R4 and R5 in the proposed standard.- M4 should be updated to reflect that the Generator Op
Response: Thank you for your comments. The regional variance must be addressed through WECC. WECC will determine if the variance should be updated accordingly.		
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) agrees with removing duplication. AE does not have any comments about the requirements, but requests the SDT review the VSL for R2 because the text does not match the requirement text.
Response: Thank you for your comments. The VSL have been updated to provide clarification and correct the difference in tenses.		
Utility System Efficiencies, Inc.	Yes	Many of the other standards that require the provision of this sort of information to the RC and neighboring entities includes a requirement that the entity respond to comments/concerns from the copied entities. Why not here?R2 appears to be a little ambiguous; does this apply to all contingency conditions? Just N-1? Only those chosen by the TOP? This would appear to be hard to determine compliance by the Region.It looks like R6 assumes that the GO has a non-LTC transformer. We are seeing LTCs in generation facilities; shouldn't this be modified to address the LTC GSUs?For M2 and M3 particularly, Evidence Retention could require a lot of data for 12 months.
Response: Thank you for your comments. The IRO standards will address the RC responsibilities. The contingencies are not		

Organization	Yes or No	Question 2 Comment
uniform across the continent, but the standard is concerned with contingencies to which the entity operates. The VAR standard does not define an entity's contingencies. R6 is focused on non-LTC transformers. An LTC would not require scheduling because the generating unit will not be taken offline to make the tap changes. There is no data retention requirement under VAR-001 for under load tap changers specifically, but the VAR-001 does provide data retention requirements generally.		
Consumers Energyu	Yes	This is a two part question with only one YES/NO answer. YES we agree with the approach. YES we have questions or comments on the remaining revised requirements.In R4, there should be a statement that the TOP will publish the exemption criteria to GOPs in the area.A consideration should be made to reserves R1 and R5. It is imperative both get the voltage schedules but if the GOP does not have them there is no control.
Response: Thank you for your comments. TOPs must notify GOPs when exemption criteria have been met. R1 sets the overarching system voltage schedule, and R5 provides GOPs with individual voltage or Reactive Power schedules.		
Exelon Companies	Yes	Yes, agree with approach, no additional comments relating to requirements. Exelon companies would vote Affirmative for VAR-001-4 if it were being balloted separately from VAR-002-3.
Response: Thank you for your comments. VAR-001-4 and VAR-002-3 were balloted separately.		
CenterPoint Energy, Houston Electric LLC.	Yes	CenterPoint Energy agrees with the SDT's efforts to eliminate duplicated standards, but has the following concerns. R1.1 is unclear on the applicability of the "30 days of a request." Is the requirement for Transmission Operators to provide their perspective Reliability Coordinators the voltage schedule automatically without a request and only to any adjacent Transmission Operators that requests the schedule within 30 days of the request; or is it the intent of the SDT for the Reliability Coordinator to also request the Transmission Operator for the schedule with the same "30 days of request" requirement. In order for a TOP to obtain evidence to prove compliance to this requirement, a TOP must receive documentable requests from its RC and/or its adjacent Transmission Operators to then provide the voltage

Organization	Yes or No	Question 2 Comment
		schedule within the 30 days of the request. If the Transmission Operators do not receive such requests then essentially according to the standard they do not have to provide the established voltage schedules as the requirement currently specifies. Many Reliability Coordinators or regions have established voltage working groups with processes or its equivalence to aid in the corroboration and defining of company specific voltage schedules within the RCs area or region then such voltage schedules would already be provided as part of the regional processes. CenterPoint Energy recommends the following clarifying language:"If requested, Eeach Transmission Operator shall provide, a copy of the voltage schedules and associated tolerance bands to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of such a request." CenterPoint Energy agrees with providing the Generator Operators the voltage or Reactive Power schedule; however, we believe R5.1, which also requires the Transmission Operator to direct the Generator Operators to comply with such schedule to the specificity that the AVR be in automatic voltage control mode, is redundant and is an unnecessary requirement as well as a compliance burden for the Transmission Operators. Exemptions to the Generator Operator to deviate from the established voltage schedule or the Automatic Voltage Regulator functioning in any mode other than automatic voltage control are addressed in R4 and VAR-002-3 R1 and R2 and will be handled in Real-Time operations and will be scenario specific. VAR-002 R1 and R2 requires Generator Operators to maintain the voltage or Reactive Power schedule and operate each generator with its AVR in service and in the automatic voltage control mode. Based upon this redundancy and Paragraph 81 criteria regarding duplicative and redundant requirements CenterPoint Energy recommends removal of the language "...and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage)".

Response: Thank you for your comments. For part 1.1, the voltage schedules are provided to the RC and neighboring TOPs within 30 calendar days of a request by either entity. The VAR-002 issues will be addressed in the next successive ballot for VAR-002. The SDT and NERC staff believes that the AVR operation in the voltage control mode is necessary for system reliability.

Organization	Yes or No	Question 2 Comment
PJM Interconnection	Yes	PJM recommends the drafting team revise R1 as follows:Each Transmission Operator shall specify a system voltage schedule. The remaining language in that requirement is not needed to support reliability.PJM does not understand the scope of controllable load in R2. We urge the drafting team to include clarification.For R3, PJM recommends revision to the Time Horizon to include Real Time only.PJM recommends the following addition to R5 as the last phrase in the requirement for consistency with R4 language. "unless otherwise exempted as noted in R4."
Response: Thank you for your comments. The additional language in R1 was added to clarify what is meant by "voltage schedule" at the request of my industry participants. Controllable load was added as FERC directive in Order No. 693. The SDT believes R3 applies to Real-time, Same-day, and Operational planning horizons.		
Tri-State Generation and Transmission Association, Inc.	Yes	In the draft of VAR-001-4 R2 the use of the word 'schedule' when referring to all reactive resources is unclear. This is in conjunction with the Compliance response to question 2 part 2, "...provide the documentation for the day ahead scheduling in addition to documentation supporting that it was scheduled..." found in the NERC document Draft Reliability Standard Compliance Guidance for VAR-001 and VAR-002 dated July 8, 2013.Is it the ad hoc group's intent to have a schedule for all reactive resources including capacitors, reactors, Static var Compensators and generators? Is the schedule meant to be similar to that of a generator (i.e. Insert capacitors at 1.0pu and remove at 1.05) or on a time base? Is schedule just supposed to take into account availability of all reactive resources?Also TSGT believes the statement "(at either the high or low side of the Generator Step-Up transformer at the TOP's discretion)" currently in VAR-001-4 R4 to should be changed to "(at an agreed upon metering point to which the GOP has direct access)." For VAR-001-4 R6 why did the ad hoc group not change the consultation requirement from GO to GOP? Tri-State believes that this information would better serve the GOP function particularly at Co-Owned facilities. This change would not have a negative effect on the reliability of the BES would reduce duplicative notification to be administered by the TOP.

Organization	Yes or No	Question 2 Comment
Response: For Requirement R2, the word schedule is used to reflect that equipment is available or on-line to provide voltage support. Compliance will review Tri-State's concerns regarding the RSAW. The VAR SDT did not agree on adding language that adds a mutually agreed upon metering point. Further, the GO is in R6 because that is the entity that would assume a loss when the unit is taken offline.		
Texas Reliability Entity		(1) Under the currently enforceable TOP standards, there is a requirement to operate within SOLs and IROLs (in TOP-004-2 R1). However, in the proposed TOP standards currently filed at FERC for approval, the wording of this requirement changed. In TOP-001-2 R8 thru R9, the TOP only has to operate within SOLs that "deserved increased attention" according to the rationale stated in the proposed Standard. What effect does that change have on these VAR requirements, and the stated rationales?(2) If it is the SDT's intent for R2 and R3 that the TOP operate within voltage SOLs, then we suggest rewording R3 to remove "as necessary" to say "within System Operating Limits" or "under normal and Contingency conditions" to match R2.(3) The VSL language for VAR-001-4 R2 and R3 does not match the wording in the requirements. If the intent is to require operation within SOLs and IROLs as suggested by the VSLs, then the requirements should expressly say so. If it is not, then the VSLs should be revised to match the requirements.(4) For VAR-001-4 R1 and R5, should there be a process to provide feedback to the TOP on the voltage schedule? For example, if the TOP sets the voltage schedule in a manner that requires the generator to be at or near a reactive limit for the unit, then the unit may not be able to provide the necessary reactive support under a contingency situation.
Response: Thank you for your comments. FERC recently remanded the TOP standards for further consideration. The "as necessary" phrase is needed to show a definitive action is not always required. The VSLs have been modified. The standard does not add a feedback mechanism on voltage schedules, but the GOPs and TOPs should be communicating as necessary for voltage coordination. However, VAR-001 does provide a vehicle for providing the criteria for studies.		
Idaho Power Company	Yes	

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP	Yes	
Luminant Generation	Yes	
PPL NERC Registered Affiliates	Yes	
Dominion	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
DTE Electric Co.	Yes	

3. **VAR-002 was modified to remove several compliance issues, and in order to address burdensome notification requirements, the VAR-001 standard has been modified to allow each TOP to tailor notification requirements based on system/area needs. Do you agree with these revisions?**

Organization	Question 3 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Adding "testing" to VAR-002 R1 was a good move. This will serve to avoid nuisance notifications for routine testing.Modifying VAR-002 R2 to allow the TOP to specify notification instructions is a good move. Each TOP will be able to specify notifications appropriate for characteristics of their transmission system. Removing the VAR-002 R3 notification of duration was a good move - the GO often does not know how long it will be out until some troubleshooting is performed. Splitting the old R3 into new R3 and new R4 was a good move. This separates two distinct types of trouble. The addition of "after becoming aware of a change in reactive capability" to the new R4 was a good move - this change is not always immediately evident. M4 should be modified to match R4 - "after becoming aware of a change needs to appear in M4".
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
PPL NERC Registered Affiliates	An additional change should be made - R3 should state that when real-time status is provided to the TOP electronically there is no need for additional notification.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
ACES Standards Collaborators	(1) Consistent with our comment number 9 in question 2, VAR-002-3 R2 and Part 2.1 need to be modified so that the GOP is only required to follow the voltage schedule if provided by the TOP. It is not desirable for the TOP to provide all generators voltage schedules. As an example, the TOP may determine it does not need to provide a voltage schedule to a small generator. To consider this situation, the clause “if a

Organization	Question 3 Comment
	voltage schedule is provided by the TOP" could be added to both Part 2.1 and the main requirement. (2) VAR-002-3 R5 meets multiple P81 criteria and should be removed. It meets Criterion A (overarching) because it does little, if anything, to benefit or protect the reliable operation of the BES and meets B2 - Data Collection/Data Retention and B4 - Reporting because it requires the GOP to gather their tap setting information and report it to a third party (i.e. its TOP) which is unnecessary to implement as a reliability requirements. A GOP is not going to refuse to provide data to its TOP on its generator step up transformer in a compliance driven world. In fact, making this data subject to compliance slows the free exchange of the information because of all the extra checking that goes into managing (i.e. verifying, checking, storing) compliance documentation. This requirement also meets B7 - Redundant because the TOP can specify this data in its data specification per TOP-003-2 R1, distribute to the GO per TOP-003-2 R3 and then GO would have to respond per TOP-003-2 R5. (3) VAR-002-3 Part 6.1 meets a P81 criterion and should be struck. It meets Criterion A (overarching) because it does little, if anything, to benefit or protect the reliable operation of the BES and meets B4 - Reporting because it requires the GO to report a technical justification for not implementing tap changes. This technical justification simply does not support reliability. The TOP can make adjustments to other voltage schedules to account for the GO's inability to implement the tap changes. What is the purpose of the GO providing the TOP a technical justification? Is it to provide the TOP some assurance there is a technical reason for failing to implement the tap changes? In a compliance driven world, the TOP can reasonably expect the GOP to implement the tap changes unless the changes would violate safety, equipment limits, regulatory or statutory requirements since these only the only deviations allowed by the main requirement. The threat of sanctions assures this. Furthermore, the GOP may legitimately not have a "technical" justification because a regulatory requirement is a legal justification not a technical justification. (4) The RSAW for VAR-002-3 indicates that compliance assessment for R4 could be vague and result in inconsistent outcomes. The RSAW indicates that the auditor will look for evidence when the GOP became aware of changes. If the entity's

Organization	Question 3 Comment
	data historian or another piece of evidence indicates a reactive capability change occurred at a certain time, does this mean that the entity is aware? We think the answer is no. The entity is only aware when its personnel become aware and not when a measurement first records that something is askew. Furthermore, we believe personnel should be limited to the plant operators in the control room who have overall responsibility. Any evidence review for when the entity became aware should be limited to plant operator logs because this evidence will most closely demonstrate what the plant operator knew based on information provided and will not be as likely to be second-guessed on what the plant operator should have known.(5) VAR-002-3 R2 will be problematic for some GOPs because it does not reflect the characteristics of the voltage schedule provided by some TOPs. For example, some TOPs provide an hourly average voltage schedule to avoid the need for notification for every time the GOP drifts out of schedule. How would R2 be applicable in this situation? Would it only apply for the first 15 minutes of each hour looking back at the last hour? Please modify the requirement accordingly to address this issue.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Texas Reliability Entity	(1) The status and capability notifications in R3 and R4 may be directly or indirectly in conflict with TOP-005-2a Attachment 1, Item 1.2.4, IRO-005-3.1a R1.1 and R12, IRO-002-2 R5, IRO-003-2 R2, TOP-006-2 R1 and R2, TOP-008-1 R4 and possibly future TOP-003-2 R1. Will the TOP and RC be able to satisfy their obligations under these other standards in view of the proposed GOP reporting parameters?(2) In VAR-002-3 R4, does the "reactive capability" include static capacitive or reactive devices that are behind the fence (for example, static capacitors and reactors installed on the low voltage feeders at wind plants to meet power factor requirements). Would this requirement apply to such devices if they are not included in the Bulk Electric System per the new BES definition?
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the	

Organization	Question 3 Comment
entire standard before posting it for another 45-day comment/ballot.	
ReliabilityFirst	1. General Comment - ReliabilityFirst believes that due to the interdependency of the VAR-001-4 and VAR-002-3 standards, the SDT should consider combining the two into a single standard. It would be a natural progression to list a requirement associated with the Transmission Operator having it immediately followed by the associated Generator Owner/Operator requirement. ReliabilityFirst believes the Generator Owner/Operator would benefit from knowing what is being required of the associated Transmission Operator. Specific VAR-002-3 Comments1. Requirement R6 - The parent Requirement R6 is applicable to the Generator Owner while the sub-part 6.1 specifies the Generator Operator. The same applicable entity listed in the "parent" requirement should be the same as any associated sub-parts. Since only Requirements are enforceable in Reliability Standards, if the Generator Operator fails to notify the Transmission Operator and fails to provide the technical justification per sub-part 6.1, a Possible Violation would be rolled up to Requirement R6. This would not work since Requirement R6 is only applicable to the Generator Owner. ReliabilityFirst completely understands that the Generator Owner is the responsible entity for ensuring that transformer tap positions are changed and that the Generator Operator is the entity responsible for actually performing the change. ReliabilityFirst recommends splitting Requirement R6 and sub-part 6.1 into two separate requirements (i.e., create a new Requirement R7 using the language of sub-part 6.1).
Response: Thank you for your comments. Based on the independent expert report, the VAR standards may eventually be combined in a single family of standards, along with the TOP and IRO standards. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Public Service Enterprise Group	1. In R1, a generator that is exempt from having to meet a voltage or Reactive Power schedule is exempt from R1. However, a generator that must meet a Reactive Power schedule should also be exempted from R1 because R1only applies to AVRs in the voltage control mode. R1 should be rewritten as follows:R1. The Generator Operator

Organization	Question 3 Comment
	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) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has been directed by its Transmission Operator to meet a Reactive Power schedule, or 3) has notified the Transmission Operator of one of the following:2. We suggest R2 have “or Reactive Power” inserted in the following phrase: “...for otherwise shall meet the conditions of notifications for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator.” 3. R2, part 2.3 should be moved to M3 since it addresses measures to prove compliance with R2. We suggest the second sentence in M2 be modified as follows: “The Generator Operator shall have evidence to show that the its generator(s) maintained the voltage or Reactive Power schedule provided by the Transmission Operator (either at the location specified by the Transmission Operator or at an alternate location that includes a methodology for converting the schedule from Transmission Operator’s location to the alternate location), or shall have evidence of meeting the conditions of notification for deviations from the voltage schedule provided by the Transmission Operator."
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Manitoba Hydro	Although Manitoba Hydro is in general agreement with the standards, we have the following comments:(1) M1 - the language in the measure is that evidence ‘must’ include which is a shift from typical language that evidence ‘may’ include. It also seems to be a shift from what is discussed in the rationale that the measure has been updated to include some of the evidence that ‘can be used’ for compliance purposes as the evidence listed is made mandatory by the ‘must’. (2) R1 - footnote 2 and 4 seems to be missing(3) M2 - refers to ‘unit’ while rest of standard refers to generator. For part 2.3, I believe the reference to ‘units’ should be to ‘Generator Operators’. (4) M3 -the acronym GOP is used while every other reference in the standard is to Generator Operator. (5) M4 - the language between the measure and the

Organization	Question 3 Comment
	requirement differs slightly. The measure requires evidence of notification within 30 minutes of 'the recognition' of a change, while the requirement requires notification within 30 minutes of 'becoming aware' of a change. (6) M5 - there is nothing in the measure that addresses the timeline upon which the Generator Owner is required to provide information. (7) R6/M6 - the requirement and measure refers to both Generator Owner and Generator Operator. Its not clear whether this is intentional or inadvertent. The words 'and provided technical justification' should be added to the end of M6 after 'tap specifications'. (8) Compliance, 1.2 - there is no time limit on the requirement for a Generator Owner to keep documentation on its step up and auxillary transformers. Its it meant to be for as long as that version is current?(9) Compliance, Compliance Monitoring, 1.3 - The language refers specifically to processes found in the NERC Rules of Procedure. Generally in draft standards, there is just a list of processes that may be used. The reference included in this draft standard is concerning because MB Hydro has their own Compliance and Monitoring program and has only adopted select aspects of the NERC Rules of Procedure.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Exelon Companies	Exelon appreciates changes made to the standard the current revision is a significant improvement on the previous draft version. As mentioned above, we support VAR-001-4 as written but feel important issues remain unaddressed with VAR-002-3 and will therefore vote Negative. Our principal concerns include: VAR-002-3 Effective Dates. The Implementation Plan for VAR-001-4 and VAR-002-3 requires the new Standard revisions to be implemented the first day of the first calendar quarter after applicable regulatory approval. Although the Implementation Plan justification states that the VAR-002 standard "cannot go into effect without the new TOP schedules and notification requirements" it does not address the implementation associated with changes to VAR-002 with respect to status notifications. This is not sufficient time to allow generating units to implement training of operators and procedural changes necessary to implement the proposed changes to notification requirements

Organization	Question 3 Comment
	associated with the AVR, PSS or alternative voltage controlling device. We suggest at least a 6 month implementation period following regulatory approval. VAR-002 R1 or in the applicability section of the standard.This standard or requirement does not account for dispersed Generation (such as wind or solar as found in the new BES definition). These generators may not have traditional AVR, may only provide limited Reactive resources and the individual elements may not have AVR or be capable of operating in Voltage control mode. VAR-002-3 R2.3Exelon believes it is reasonable to allow the GOP to monitor the voltage at the location specified in their TOP issued voltage schedule by allowing the GOP to monitor at a different location by applying a methodology for converting the voltage monitored; however, the conversion method should be communicated and agreed to by the Transmission Operator. There is not a one for one conversion between grid voltage and terminal voltage and both parties should agree on the conversion method and monitoring point to avoid any future audit or implementation issues.VAR-002-3 R3Exelon agrees with the fifteen (15) minutes to allow a GOP time to resolve an issue before having to notify the TOP of a status or capability change; however, postponing the notification by 15 minutes to alleviate short term / nuisance notifications has the effect, as written, of shortening the notification window to 15 minutes. Fifteen minutes is not a reasonable timeframe for such notifications to occur, especially in large dispersed fleet operators where the GOPs do not communicate directly to their TOP and must notify via a third party (e.g., an independent generation dispatching organization). Exelon suggests that the 30 minute notification timeframe for a status change on the AVR, PPS or alternative voltage controlling device be started following the inability to restore within 15 minutes.VAR-002-3 R4Exelon suggests that the VAR SDT provide guidance to the industry on examples of reactive capability changes that would require notification to the TOP within 30 minutes after becoming aware of a change. The only guidance provided to date is in the VAR-002 Compliance Analysis Report dated August, 2010.

Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the

Organization	Question 3 Comment
entire standard before posting it for another 45-day comment/ballot.	
Florida Municipal Power Agency	FMPA appreciates these changes. However, VAR-002-3 remains duplicative of other requirements within the standardsVAR-002-3 R2, bullet 2.3 is duplicative of TOP-001-2 R1. Both require the GOP to follow the direction of the TOP. Bullet 2.3 should be deleted.VAR-002-3 R5 is duplicative of TOP-003-2 and should be deleted. VAR-002-3 R5 requires the GO to provide the TOP information about the GSU. TOP-003-2 R5 requires the GO to submit data as specified by the TOP. The TOP cannot perform their obligations of VAR-001-4 R6 to specify GSU tap positions without the data of VAR-002-3 R5; however, the TOP will ask for that data in accordance with TOP-003-2 R3. Hence, these requirements are redundant and VAR-002-3 R5 ought to be deleted.FMPA also wonders how duplication between TOP-003-2 that gives TOPs a carte blanche opportunity to develop data requests on any information they need and the notification requirements of VAR-002-3 will be managed. In other words, the TOP can develop their TOP-003-2 data specification to include the notification requirements of VAR-002-3 and as such GOPs would be subject to double jeopardy risk.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Utility System Efficiencies, Inc.	For R2, what about the situation where the generator cannot actually influence the voltage? There may be a significant amount of hours where they can't keep the voltage in range. For M2, for a generator that does not have an AVR, what type of evidence is required to show compliance for 8760 hours per year? Sounds like a lot of evidence potentially.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Tri-State Generation and	For VAR-002-3 R5 TSGT believes the TOP should consult with the GOP rather than

Organization	Question 3 Comment
Transmission Association, Inc.	the GO to better align requirement R5 with its subrequirement R5.1.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Consolidated Edison Co. of NY, Inc.	Generators may be asked by their TOP to operate in other modes. Reword Requirement R1 as follows: 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) unless the Generator Operator 1) is exempted by the Transmission Operator, [delete: or] 2) is notified by the Transmission Operator to operate in a different viable operating mode (e.g., constant VAR output mode), or 3) has notified the Transmission Operator of one of the following:
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Consumers Energyu	It is important to clarify the statement of “notification requirements.” In the context of VAR-002 this term refers to the notification from the GOP to the TOP on status of the AVR, Ability to follow the voltage schedule or the status of the unit.We would suggest the timing on VAR-002 R3 be similar to R4 in that the clock starts at the awareness of the GOP of a status change.VAR-001 clearly defines a Voltage or Reactive Power schedule. We suggest this be done in VAR-002 for consistency rather than the footnotes provided.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Luminant Generation	Luminant appreciates the work of the SDT and agrees that most of the revisions are appropriate, and that the intent of the SDT to allow for more than one method of voltage support is correct. However, as written, VAR-002, R2, does not clearly

Organization	Question 3 Comment
	identify that generators can provide voltage support by a method other than maintaining a voltage schedule, continuously monitoring voltage and reporting deviations from the voltage schedule. In some areas of the country, the TOP monitors the voltage at all busses in it area, including the busses connecting generators, and directs generators to modify reactive output as the TOP requests. Luminant believes the language of VAR-002, R2 should be modified to provide clarity as follows:R2. Unless exempted by the Transmission Operator, each Generator Operator shall provide generator voltage support or Reactive Power support (within each generating Facility's capabilities4) as follows: [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 provide voltage or Reactive Power support directed by the Transmission Operator. 2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the request cannot be met. 2.3. When directed by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule3 (within each generating Facility's capabilities4) provided by the Transmission Operator, and shall meet the conditions of notification for deviations from the voltage schedule provided by the Transmission Operator. 2..3.1 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. With this proposed language, the GOP would have to maintain a voltage schedule and report deviations only if that is the normal method of voltage support requested by the TOP. 2.3 and 2.3.1 would only apply to a GOP that maintains a voltage schedule. The measures for 2.1 and 2.2 would include operator logs, voice recordings, etc.

Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.

Organization	Question 3 Comment
Duke Energy	No. Duke Energy does not agree with the revisions made.Duke Energy is unclear whether the exemptions referenced in R1 and R2 in VAR-002-3 are the same as the exemptions created in VAR-001-4 R4. We believe using the word “exempted” in multiple requirements without identifying the origin of the exemption is a cause of confusion. Requirement 2 - Revise R2.1 to read,” When a generator’s AVR is out of service, the generator does not have an AVR, or is not in a TOP approved mode of AVR operation as specified in R1, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator. “The VRF/VSL for Requirement 2 would need to be modified if this change is made.Requirement 3 - Duke Energy is unclear as to what is considered an alternative voltage controlling device. Duke Energy prefers the language in the previous draft of this standard which states, “Each Generator Operator shall notify its associated Transmission Operator of a status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability within 30 minutes of the change. If the status has been restored within the first 15 minutes of such change, then there is no need to call the TOP. “The language in the previous draft provides more clarity on what would prompt notification from a GOP to a TOP based on status or capability change.Requirement 5 - Duke Energy would like the SDT to review and verify that the Transmission Planner, and not the Planning Authority or Planning Coordinator, is the correct functional entity for this requirement. Lastly, Duke Energy would like to clarify that we encouraged our ballot body members to vote “Negative” on this ballot for reasons stipulated above. However, one of our ballot body members mistakenly voted “Affirmative” which was in error. Our decision to vote “Negative” on this ballot was unanimous among all those involved. We apologize for any confusion this may have caused.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	

Organization	Question 3 Comment
Kansas City Power & Light	NO. R2 is the part of VAR-002 that I disagree with because the Transmission System Operator is monitoring the system voltage and notifies each generating facility when they need to raise/lower voltage in that particular area of the system. If the voltage at the generating facility is high/low the TSO has received an alarm and will be notifying the plants control operator to correct the voltage and there already is a requirement for the control operators to comply with the TSO request.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Portland General Electric Co	PGE appreciates NERC's efforts to revise VAR-002. The standard as whole is a significant improvement from the previous version. However, R3 still requires a 30 minute notification for notifying the transmission operator (TOP). The 30 minute limit is a challenge for generator operations to meet. The SDT should consider increasing this limit to 60 minutes. In addition, the requirement should allow registered entities to set up an alternative method to provide real-time AVR/PSS/voltage control device telemetry. This method would eliminate a need for notifying the transmission operator within 30 minutes. Also, the NERC glossary should fully define the term, 'voltage controlling device', as stated in R3.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
American Electric Power	R5: Rather than allowing only 30 days, we instead recommend that the Generator Owner be allowed to provide the data within the timeframe agreed upon by the GO and either the Transmission Operator or Transmission Planner. This data is often part of larger data submission that may stretch beyond the proposed time horizon. In addition, providing this data to the TP appears to be duplicative of the MOD standards currently being updated. As a result, we recommend removing the TP from this requirement.R6: We recommend that Requirement 6 and its subrequirement be applicable only to the Generator Owner and not split between the Generator Owner

Organization	Question 3 Comment
	and Generator Operator. If both are to be retained, we recommend that the subrequirement be changed to state “*If* the Generator Owner cannot provide tap setting changes as requested, the Generator Owner or Generator Operator should notify the Transmission Operator...”
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Bureau of Reclamation	Reclamation believes that the notification requirements in R2 and R3 should provide the continent-wide standard. Reclamation suggests that the bullet points in R1 should be relabeled as sub-requirements R1.1 and R1.2.Reclamation requests that the drafting team clarify the timeframe for notifications required by R1. Reclamation suggests that the drafting team update VAR-002-3 R2 to allow Generator Operators to notify Transmission Operators that a voltage schedule cannot be met for equipment or other reasons, so that the Transmission Operator can alter the voltage schedule accordingly. R2.2 recognizes that a Generator Operator can provide an explanation that a voltage schedule cannot be met “when directed to modify voltage” but does not address the planning horizon. Reclamation appreciates that R2 recognizes that generators only need to comply with voltage schedules within facility capabilities, and that footnote 6 recognizes that generating facility capability may not be sufficient at times to pull the system voltage within scheduled tolerance bands. Nevertheless, Reclamation believes that R2 subrequirements should more clearly articulate that (1) Generator Operators should provide Transmission Operators with feedback that they cannot meet voltage schedules in the planning horizon, and (2) generators may not always be capable of modifying system voltage.Reclamation notes that R2.3 applies to real-time operations, and suggests that R2.3 should be updated to require Generator Operators and Transmission Operators to monitor voltage at mutually-agreed upon locations to avoid confusion in real-time communications. Reclamation suggests that the drafting team update VAR-002-3 R3 to specify that the “Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative

Organization	Question 3 Comment
	voltage controlling device within 30 minutes of becoming aware of the change." Reclamation also suggests that M3 should be updated to specify that the GOP must notify its associated Transmission Operator "within 30 minutes of becoming aware of the change" rather than "within 30 minutes of when the change first occurred." Reclamation notes that VAR-002-3 R4 specifies that the "Generator Operator shall notify its associated Transmission Operator within 30 minutes after becoming aware of a change in reactive capability... ." Reclamation suggests that M4 should be updated to match this language and specify that the GOP must notify its associated Transmission Operator "within 30 minutes of becoming aware of the change" rather than "within 30 minutes of when the change first occurred." Reclamation requests clarification on types of "changes in reactive capability" that could trigger the notification requirement in R4. Reclamation notes that the time horizon for VAR-002-3 R6 should probably be changed from "Real-Time Operations" to "Operations Planning" to match VAR-001-4 R6 and reflect that tap setting changes are agreed upon in advance rather than in real-time. Reclamation suggests that VAR-002-3 R6 should be updated to match VAR-001-4 R6 and to specify that the Transmission Operator must coordinate outages to accommodate required step-up transformer tap changes. Reclamation suggests the drafting team update the requirement to read "After consultation with the Generator Owner regarding necessary step-up transformer tap changes, associated outages, and the implementation schedule...".
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Northeast Power Coordinating Council	Suggest the following changes to more effectively convey the intents of Measure M3 and Requirement R6.Suggest that Measure M3 be reworded to require demonstration of compliance rather than to require actions which should have been stipulated in the requirement. Specifically, we proposed the last part in Measure M3 be revised to:"...therefore, if a status change lasts more than 15 minutes, the GOP shall provide evidence such as system log, electronic message or a transmittal letter that it notified its associated Transmission Operator within 30 minutes of when the

Organization	Question 3 Comment
	change first occurred."Regarding R6, the wording "the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator..." is not a direct action and may not be measurable. Suggest revising it to read:"the Generator Owner shall implement the transformer tap positions according to the specifications provided by the Transmission Operator...."We further propose that the SDT insert the evidence language into the first sentence of Measure M3 which asks for evidence that the Generator notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3.Generators may be asked by their TOP to operate in other modes. Reword Requirement R1 as follows: 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) unless the Generator Operator 1) is exempted by the Transmission Operator, 2) is notified by the Transmission Operator to operate in a different viable operating mode (e.g., constant VAR output mode), or 3) has notified the Transmission Operator of one of the following:... The comments in Question 2 regarding Hydro-Quebec regarding the word "schedule" apply.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
PacifiCorp	The following change to requirement R4 is recommended: "Reactive capability changes due to change in the wind speed for wind generators or a change in the solar resource for solar facilities do not require Transmission Operator notification." Given the variable nature of wind, the reliance of weather forecasting does not rest explicitly with the GOP. The TOP has access to weather forecasting that would make the need of notification by the GOP unnecessary.Additionally, PacifiCorp supports the following comments from MidAmerican:We support the deletion of the language regarding notification of the expected duration of a change in status. At the time a status change occurs it is often difficult to provide a meaningful estimate of the duration of the change. Requirement 3 should be revised to state - Notification must

Organization	Question 3 Comment
	be made within 30 minutes of becoming aware of the change from automatic controlling voltage for the AVR, and from in-service of the PSS. Measure 3 should be revised to reflect this as well.The revised VAR-002 R2.1 removes the 15 minute deviation criteria for notification by Generator Operators to Transmission Operators. The revised VAR-001-4 requires Transmission Operators to provide notification requirements. The drafting team in the consideration of comments explained "In an effort to remove prescriptive notification requirements for the entire continent" the change was made. This leaves the Generator Operators at the mercy of Transmission Operators who could potentially set a no deviation criteria. It is recommended that a comprise be struck by specifying a limit on the criteria such as "no less than 15 minutes".
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
MRO NSRF	The revised VAR-002 R2.1 removes the 15 minute deviation criteria for notification by Generator Operators to Transmission Operators. The revised VAR-001-4 requires Transmission Operators to provide notification requirements. The drafting team in the consideration of comments explained "In an effort to remove prescriptive notification requirements for the entire continent" the change was made. This leaves the Generator Operators at the mercy of Transmission Operators who could potentially set a no deviation criteria. It is recommended that a compromise be struck by specifying a limit on the criteria such as "no less than 15 minutes".For clarification it is recommended that the word "generator" be added before the word "stability" in the last sentence of footnote 6. [Note to NSRF: a comment on this was submitted previously but it did not have a recommended language change]In M2 it is recommended that "alarm logs" be added to the list of evidence. We support the deletion of the language regarding notification of the expected duration of a change in status. At the time a status change occurs it is often difficult to provide a meaningful estimate of the duration of the change. Requirement 3 should be revised to state - Notification must be made within 30 minutes of becoming aware of the

Organization	Question 3 Comment
	change from automatic controlling voltage for the AVR, and from in-service of the PSS. Measure 3 should be revised to reflect this as well.The following change to requirement R4 is recommended: "Reactive capability changes due to factors such as a change in the wind speed for wind generators or a change in the solar resource for solar facilities do not require Transmission Operator notification"Measure 4 should be revised to reflect the wording in Requirement 4 - Notification must be made within 30 minutes of becoming aware of the change of state of the AVR.For the same reason described above for VAR-001 (NERC IGVT Report), R1 should be modified as follows:"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) or plant-level volt/var regulator in service and controlling voltage) unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has notified the Transmission Operator of one of the following:" A similar addition should be made where the AVR is referred to in the other requirements of VAR-002.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Independent Electricity System Operator	We agree with most of the proposed changes, but would suggest the following changes to more effective convey the intent of Requirement R3 and Measure M3.a. R3: The wording "the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator" is not a direct action and may not be measurable. We suggest to revise it to read:"the Generator Owner shall implement the transformer tap positions according to the specifications provided by the Transmission Operator...."b. M3: We suggest it be reworded to require demonstration of compliance rather than to require actions which should have been stipulated in the requirement. Specifically, we proposed the last part in Measure M3 be revised to:"...therefore, if a status change lasts more than 15 minutes, the GOP shall provide evidence such as system log, electronic message or a transmittal letter that it notified its associated Transmission Operator within 30

Organization	Question 3 Comment
	minutes of when the change first occurred."We further propose that the SDT insert the evidence language into the first sentence of Measure M3 which asks for evidence that the Generator notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3.We assess the changes proposed under Q2 and Q 3, above, are not substantive and do not materially change the intent or content of the standards. Therefore, if the standards receives 2/3 majority approval at the ballot, these changes can be implemented and posted for recirculating ballot without having to post and ballot the standards for a successive ballot.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
ISO/RTO Standards Review Committee	We assess the changes proposed under Q2 and Q 3, above, are not substantive and do not materially change the intent or content of the standards. Therefore, if the standards receives 2/3 majority approval at the ballot, these changes can be implemented and posted for recirculating ballot without having to post and ballot the standards for a successive ballot.We agree with most of the proposed changes, but would suggest the following changes to more effective convey the intent of Requirement R3 and Measure M3.a. R3: The wording "the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator" is not a direct action and may not be measurable. We suggest to revise it to read:"the Generator Owner shall implement the transformer tap positions according to the specifications provided by the Transmission Operator...."b. M3: We suggest it be reworded to require demonstration of compliance rather than to require actions which should have been stipulated in the requirement. Specifically, we proposed the last part in Measure M3 be revised to:"...therefore, if a status change lasts more than 15 minutes, the GOP shall provide evidence such as system log, electronic message or a transmittal letter that it notified its associated Transmission Operator within 30 minutes of when the change first occurred."We further propose that the SDT insert the evidence language into the first sentence of Measure M3 which asks for evidence that the Generator

Organization	Question 3 Comment
	notified its associated Transmission Operator within 30 minutes of the change identified in Requirement R3.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Ameren	We request that the SDT support adding to R3 the "...after becoming aware of..." language now proposed for R4. This will help reduce the number of unnecessary GOP notifications to the TOP.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Arizona Public Service Company	Yes
Salt River Project	Yes
Tennessee Valley Authority	Yes
The United Illuminating Company	Yes
CenterPoint Energy, Houston Electric LLC.	Yes, CenterPoint Energy agrees with these revisions to VAR-002 removing compliance issues that address burdensome notification requirements, allowing the Transmission Operator, through VAR-001 to tailor notification requirements based on system/area needs.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	

Organization	Question 3 Comment
Idaho Power Company	Yes, exempting the intermittent outages of AVR's and only requiring notification for extended interruptions is an improvement and lessens the documentation necessary to show compliance.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Ingleside Cogeneration LP	Yes,Ingleside Cogeneration agrees that there must be reasonable notification criteria controlled by TOPs that allows them to specify when notification of change in AVR or reactive resource status is necessary. In many cases, the status is telemetered in real-time, but a call is required anyways to specify the expected duration of the status change. This is overcommunication in most cases, and only serves to tie up resources at the GOP and TOP.The same is true of notifications when the GOP cannot maintain the voltage at the interconnection point. Many GOPs do not control interconnection voltage and could actually resist an adjustment that the TOP is trying to make in response to system conditions. Again, some reasonable notification criteria could stop a lot of nuisance calls under these circumstances.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
City of Austin dba Austin Energy	Yes.
PJM Interconnection	Yes.
EDP Renewables North America LLC	Yes. EDPR NA believes it is important for TOPs to have the flexibility to tailor its requirements, as long as there is sufficient coordination among affected entities. We also offer the following comment:VAR-002 R1: We support the concept that a GOP need not notify its TOP that its AVR is out of service if it has previously advised its TOP that it will not have its AVR in service during start-up and shut-down. We

Organization	Question 3 Comment
	recommend that similar provision be made for variable energy resources which are not able to provide voltage support when operating in similar circumstances. Wind farms, for example, generally have equipment limitations that can affect their ability to follow voltage schedules when operating at low levels. Wind farms will not telemeter a different status in that circumstance, however. We propose that, if a variable energy resource has notified its TOP of equipment limitations that affect its ability to follow a voltage schedule until it achieves a certain level of production, also not be required to notify the TOP that its AVR is out of service.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Bonneville Power Administration	Yes. Comments: BPA requests further clarification of VAR-002-3 R3 and M3, to be revised such that a status or capability change in generator Reactive Power should be reported within 30 minutes from an entity becoming aware of the change in condition, rather than the current form, which is 30 minutes from the change in condition.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
SPP Standards Review Group	Yes. We also offer the following comments on the two standards.Generic Comments on VAR-001-4We recommend changing 'real time' in the Purpose to 'Real-time' as defined in the NERC Glossary of Terms.We suggest rewording R1.1 to the following: 'Each Transmission Operator shall provide a copy of the voltage schedules as specified in R1 to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of such a request.' Although we have proposed deleting R2, if the drafting team decides to keep it, we recommend deleting the last sentence in R2. It is really an example and doesn't contribute substantially to the requirement.We also recommended deleting R3 but if the drafting team decides to keep it, we suggest adding 'to operate within SOLs and IROLs' following 'as necessary' at the end of the

Organization	Question 3 Comment
	requirement.The use of the term ‘direct’ in R3 and R5.1 lead to implications of issuing directives. To get away from this situation, we suggest substituting ‘instruct’ for ‘direct’. This change will also need to be reflected in the Measures and the VSLs.Since R4 contains an exemption for R5, we suggest reordering requirements R4 and R5 such that R5 becomes R4 and R4 becomes R5. That way the exemption follows the requirement.We suggest the drafting team delete the phrase ‘...at the Transmission Operator’s discretion.’ at the end of R5. We suggest changing ‘associated’ to ‘applicable’ in and deleting the redundant phrase at the end of R5.1. The requirement would then read: ‘The Transmission Operator shall provide the voltage or Reactive Power schedule to the applicable Generator Operator.’ The Measure will also need to be revised to correspond with the revised requirement.We recommend adding ‘for that criteria’ following ‘request’ at the end of R5.3.We recommend changing the Time Horizon in R6 to Long-Term Planning since the Transmission Planner is typically the entity that will determine when a tap change is necessary and will notify the Transmission Operator that it needs to be done.In the Rationale Box for R6 there is a reference to VAR capability and tap setting. We suggest rewording that sentence to the following: ‘If the tap setting is not properly set, then the VARs available from that unit can be affected.’The Severe VSL for R3 contains ‘real-time’. It needs to be ‘Real-time’.Generic Comments on VAR-002-3The use of the term ‘direct’ in R2.2 lead to implications of issuing directives. To get away from this situation, we suggest substituting ‘instruct’ for ‘direct’. This change would need to be reflected in the Measure 2.1 and 2.2 and the VSL also.We suggest changing the notification timing requirements in R3 to the Generator Operator must notify the Transmission Operator within 30 minutes of the change of AVR status unless the AVR has been restored to service.In the second sentence in the Rationale Box for R3, use ‘provide’ instead of ‘provided.’In the Rationale Boxes for R5 and R6 there is a reference to VAR capability and tap setting. We suggest rewording that sentence to the following: ‘If the tap setting is not properly set, then the VARs available from that unit can be affected.’

Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire

Organization	Question 3 Comment
standard before posting it for another 45-day comment/ballot.	
Xcel Energy	Yes. Xcel Energy appreciates the hard work of the Standard Drafting Team. We recognize that significant effort has been put into the modifications of the VAR-001 and VAR-002 standards and we applaud the direction the team is moving. We are voting Negative on VAR-002 for one reason which we explain below.Xcel Energy understands that the existing language in the VAR-002 standard uses the term “status change” but believe that this term is not well defined and is subject to different interpretations. AVRs and PSSs are designed to cycle based on the parameters being monitored by the devices. This as-designed cycling may be interpreted as a status change. We note here that the drafting team does not use the term status change in its rationale statement. Instead, the rationale statement is much clearer in meaning than the proposed requirement language. To address Xcel Energy’s concern, we request that the drafting team replace the first sentence in Requirement R3 with the following sentence. (We believe that this change does not constitute a significant modification but is instead providing more clarity in the requirement language based on the wording of the Rationale for Requirement R3.)”Each Generator Operator shall notify its associated Transmission Operator when the AVR, power system stabilizer, or alternative voltage controlling device goes out of service within 30 minutes of the change.”
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Electric Reliability Council of Texas, Inc.	Yes.ERCOT supports the revisions but recommends that the SDT consider the following additional issues:A. Consider revising R2 as follows: “The generator shall follow the voltage schedule assigned by its TOP.” Otherwise this is effectively a “fill in the blank” standard.As drafted, R2 also establishes “how” entities are required to meet their obligations. The standards should establish what is required and leave it to the discretion of the functional entity to determine how to meet the relevant objective. R3 provides the needed notification.B. VAR-002 R2 requires GOs to notify

Organization	Question 3 Comment
	TOPs of voltage. This seems to create an unnecessary requirement given that TOPs are obligated to monitor system voltage.C. VAR-002 R2.1 appears to require that GOs maintain the voltage assigned. Consistent with the general principle that the standards should establish what is required, how GOs maintain voltage assignments should be within the discretion of the entity.D. VAR-002 R2.2 is redundant. If GOs have to maintain the voltage assigned, this is unnecessary.E. VAR-002 R2.3 is redundant if a GO has to maintain the voltage assigned.F. VAR-002 M2 includes a statement that has a "will" in it. This effectively establishes a requirement. Measures are means of demonstrating compliance, they are not requirements. The measure should be revised accordingly.G. VAR-002 R3 should state that the notification is not required during startup or shutdown. A TOP can determine from telemetered information when a unit is operating below their lower stability limit. Requiring reporting of AVR/PSS status coming on/going off line is not necessary and creates unnecessary distractions that could undermine reliability.H. The 2nd sentence of R3 is redundant with the 1st. If notification is required within 30 minutes it is implicit that the entity does not have to notify within 15 minutes? I. If a GO maintains the assigned voltage, the status of a GO's AVR is irrelevant. If a GO failed to maintain the assigned voltage they are in violation of R2 regardless of the reason. M3 seems to unnecessarily create the potential for double violation issue on a reporting obligation.J. The standard should make clear that telemetry on status of AVRs and PSSs to TOPs meets this notification obligation. The term 'notify' seems to imply a manual written or verbal communication.K. VAR-002 R4 second sentence dealing with 15 min language- - please refer to R3/M3 comments.L. VAR-002 R5 - This requirement is unnecessary if GOs have to respond to any reasonable data request from their TOP.M. VAR-002 R6 is redundant with R2. If a GO has to maintain assigned voltage, and adjusting taps is necessary to do that, then this instructional requirement is not needed. If R6 is kept, in VAR-002-3 Standard the entity changes in R6.1. VAR-001-4 states the TOP will work with the GO in R6. Then in VAR-002-3 it states the following:R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that

Organization	Question 3 Comment
	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 Operator cannot comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification. Why does it change from the GO to the GOP? The SDT should address the differences within VAR-002-3 to mirror R6 in the VAR-001-4 Standard.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Dominion	Yes.In order to be consistent, Dominion also suggests reviewing the need to use "its associated Transmission Operator" throughout the entire standard (i.e. R1 - "has notified the Transmission Operator", R2/M2 - "provided by the Transmission Operator", R6 - "specifications provided by the Transmission Operator", etc).
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
DTE Electric Co.	YesComments: Adding the 15 minute window in VAR-002 is a great improvement.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	

4. **The VRFs/VSLs for VAR-002 were modified to remove arbitrary time requirements. Do you have any specific comments or questions about the new VSLs/VRFs?**

Organization	Question 4 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	The removal of "up to 45 minutes for the R2 VSL was a major improvement.The comma in the second and third OR statements of the Severe VSL for VAR-002 R2 is not needed. The comma in the second OR statement of the Severe VSL for VAR-002 R6 is not needed.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Manitoba Hydro	(1) VSLs, - not clear why the references throughout the VSLs are to 'responsible entity' when the requirements are clear as to an obligation on either the Generator Owner or Generator Operator. Those entities should be listed in the VSLs as they are in the requirements and standards. (2) VSLs, R2, Severe VSL - the word 'Power' is missing after 'Reactive'. Also doesn't mention that the Generator Operator 'did not have an exemption'. (3) VSLs, R3 and R4 - would read better if stated 'the Generator Operator did not make the notification of a change that lasted more than 15 minutes within 30 minutes of the first occurrence of the change as required'.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	

Organization	Question 4 Comment
CenterPoint Energy, Houston Electric LLC.	CenterPoint Energy believes the VSLs associated with VAR-001 R2 and R3 do not consider changes in Real-Time topography such as forced outages, Resource inadequacy, or changes in weather that can drastically change the outcome of any planned or studied environment in both normal and emergency operations. A transmission operator could have scheduled sufficient reactive resources as necessary and have them available to mitigate known and identified SOLs or IROLs, but cannot schedule sufficient reactive resources for the unknown. CenterPoint energy suggests adding “identified” to the VSL language. “The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an identified SOL or IROL”. CenterPoint energy believes that the High VSL for R4 is inappropriate and is indicative of a zero tolerance environment. If a Transmission Operator has an exemption criteria established, notifies the Generator Operator of such exemption, and captures evidence for compliance to prove notification 99 times out of 100, then the one instance in which the TOP notified the Generator Operator, but failed to capture evidence would warrant a High VSL possible violation.
Response: Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, the SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Xcel Energy	If the drafting team makes the requested modifications to the requirements, Xcel Energy has no concerns with either the VSLs or VRFs.
Response: Thank you for your comments.	
Utility System Efficiencies, Inc.	No
Idaho Power Company	No
Tennessee Valley Authority	No comments

Organization	Question 4 Comment
Salt River Project	No.
Bonneville Power Administration	No.
Kansas City Power & Light	No.
EDP Renewables North America LLC	No.
City of Austin dba Austin Energy	No.Because NERC has not provided an area for "Additional Comments," we are adding them here.The City of Austin dba Austin Energy (AE) commends the Standard Drafting Team's efforts related to Project 2013-04. The quality of the standard is enhanced over previous approved versions, providing additional clarity and compliance sensitivity. AE respectfully submits the following comments on VAR-001-4 and VAR-002-3 to the Standard Drafting Team (SDT):VAR-002-3, R1, Pertaining to the phrase "... unless the Generator Operator 1) is exempted by the Transmission Operator, or 2) has notified the Transmission Operator..." AE recommends the SDT clarify whether the TOP may exempt all the units represented by a GOP, or instead, specific generating facilities or a generator bus. AE suggests altering the language to read "... unless 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator..." This change will make the language in VAR-002-3 R1 consistent with the language in VAR-001-4 R4.VAR-002-3, R2.3: The requirement makes it mandatory for Generator Operators to monitor the voltage at the location specified in the voltage schedule or have a methodology for converting the scheduled voltage specified by the TOP. This may imply that the Generator Operator should make voltage corrections independent from the TOP. AE believes that maintaining the appropriate transmission level voltage is the key for sustaining system stability and that responsibility falls on the TOP. Because the TOP already monitors the transmission level voltages, the R2.3

Organization	Question 4 Comment
	requirement for GOPs to monitor voltage is redundant and may create a situation where the TOP and GOP do not agree on the monitored value (i.e. the voltage readings can be different due to step-up voltage equipment). To avoid confusion and potential compliance ambiguities, AE suggests the standard specifically state TOPs are responsible for monitoring the system voltage schedule and notifying the GOP when voltage drifts outside acceptable parameters. This appears to be a common practice of operating the grid. The GOP will be responsible for meeting the reactive support requested by the TOP. If the GOP cannot meet the reactive support requested by the TOP, the GOP should have to notify the TOP. AE suggests the following: Add “Transmission Operators” under R4 - “4.3 Transmission Operators”, and alter R2.3 to: “Each Transmission Operator shall monitor the system voltage and notify its associated GOPs for additional voltage support if system voltage fails to meet the voltage schedule. If the GOP cannot meet the reactive support requested by the TOP due to equipment limitations, it shall notify the TOP of the limitations within 15 minutes.VAR-002-3, R4: AE believes the phrase “a change in reactive capability” is vague. As written, even the slightest change in reactive capability must be reported to the TOP. Is it the SDT intent the TOP be notified if a reactive capability (leading or lagging) of a generation resource changes by 1 MVAR? Detecting and reporting small reductions in reactive capability will create onerous reporting. AE recommends the following for R4: “Each Generator Operator shall notify its associated Transmission Operator within 30 minutes that a resource’s reactive capability changed by 20 MVAR or 10%, whichever is greater, of the previously provided reactive capability due to factors other than a status change described in Requirement R3.”
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
American Electric Power	R3 & R4 do not require communications for all instances. As a result, the severe VSL text must be qualified so that it only applies to those situations where notification is actually necessary.

Organization	Question 4 Comment
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Bureau of Reclamation	Reclamation suggests that the VSLs for VAR-002-3 R3 and R4 should reflect a range of noncompliance like in VAR-002-2. A failure to notify the Transmission Operator of an AVR, power system stabilizer, or reactive capability change for 35 minutes should not be treated the same as a failure to notify the Transmission Operator of the status change for 75 minutes.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Duke Energy	See our comments on VAR-002 Requirement 2.
Arizona Public Service Company	The VRF of “high” is not justified for any of the requirements. We would suggest a VRF of “medium” or “low”. If the drafting team thinks a VRF of “high “ is justified, some reasoning should be provided by the team. Lack of documented voltage schedules does not mean the system is being operated unreliably. Units are still being operated in AVR mode as required by other schedules and transmission operators coordinate the voltage schedules as needed.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
PPL NERC Registered Affiliates	Time requirements are not necessarily arbitrary, and it is in fact important to establish explicit and meaningful criteria regarding the acceptable time (and magnitude) of voltage schedule deviations. The principal reason that VAR-002 has been so troublesome in the past is that one could interpret a 10 MW hydro unit being out of the bandwidth by 0.1 kV for 1 minute as constituting a violation, despite there being no meaningful impact on BES reliability. There are moreover many occasions when a the system voltage unavoidably strays briefly outside the bandwidth due to a

Organization	Question 4 Comment
	disturbance or because there are step-changes in the TOP's voltage schedule. VAR-002-3 makes a slight movement in the right direction by stating in R2 that a unit must keep within the bandwidth or, "meet the conditions of notification," but there is nothing in VAR-001 or 002 to require TOPs to create justifiable requirements in this respect. We presently suffer under a system in which meaningless violations are spawned by abusive practices, such as establishing a bandwidth of only +/- 0.5%, and VAR-001 and 002 should be revised in a fashion that prohibits such practices.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
ACES Standards Collaborators	We do not support the VSLs for R5 because it meets P81 criteria and should be removed. We also do not support the VSLs for requirements that need modifications as identified in question 3.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
SPP Standards Review Group	We suggest the following change for the High VSL for R2. The responsible entity did not have a conversion methodology when it monitored voltage...'We recommend replacing the word 'directive' with 'specification' in the Severe VSL for R6.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	
Northeast Power Coordinating Council	We support the proposed VRFs and VSLs.
ISO/RTO Standards Review Committee	We support the proposed VRFs and VSLs.

Organization	Question 4 Comment
Independent Electricity System Operator	We support the proposed VRFs and VSLs.
Exelon Companies	We understand that R3 and R4 are binary requirements, (did or did not notify in 30 minutes), but it seems unreasonable that a complete failure to notify would have the same VSL as a notification that is one or five minutes late.
Response: Thank you for your comments. Since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.	

Additional Comments:

Seminole Electric
Bret T. Galbraith

VAR-001-4 Comments

(1) Requirement R2 states the following:

"Each Transmission Operator shall schedule '**sufficient reactive resources to regulate voltage levels'** under normal and Contingency conditions." (emphasis added)

Seminole requires clarification concerning the phrase "sufficient reactive resources to regulate voltage levels." Seminole requests additional clarity as to what it means to regulate voltage levels, e.g., does this mean to operate within SOLs? Please add clarity to the language of the Requirement, and not in guidance documents. Seminole believes adding clarity will assist auditors in determining what is "sufficient."

(2) Requirement R3 states the following:

"Each Transmission Operator shall operate or direct the Real-time operation of devices to '**regulate transmission voltage and reactive flow as necessary'**." (emphasis added)

Seminole believes that the language “as necessary” does not provide enough due process notification of what is required. Seminole would like clarification as to what is necessary, for example, “necessary to ensure sufficient voltage support to prevent …”

VAR-002-3 Comments

(1) Requirement R1. defines “start-up” as ending “when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.” The drafting also defines “shutdown” as beginning “when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.” Seminole reasons that these definitions for “start-up” and “shutdown” inaccurately describe generator start-up and shutdown in the traditional meaning of these terms. For example, operators may consider start-up to cover the generator load above the minimum sustainable load value to base load for environmental permitting regulations. It appears that the drafting team is attempting to define a unique generator operational region, and therefore, Seminole suggests that the drafting team utilize different terms than “start-up” and “shutdown” in order to prevent confusion.

However, the drafting team does not define “testing mode,” and Seminole reasons that without additional guidelines, such as qualitative and quantitative factors, the misinterpretation of “testing mode” is a concern. Therefore, Seminole requests the drafting team to describe in greater detail “testing mode.”

(2) Requirement R3 states the following:

“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 the first ‘**15 minutes’** of such change, then there is no need to notify the Transmission Operator.” (emphasis added)

Reviewing the timeframes listed, it appears the numbers are significant to the whole number value. Therefore, if an entity has an AVR status change that lasts 15 minutes and 29 seconds, that AVR status change does not need to be reported, because proper significant digits rounding will round that value to 15 minutes and not 16 minutes. Please clarify the significant digit in these timeframes, i.e., is it 15, 15.0, 15.00, 15.0000, etc.?

Response: Thank you for your comments. The phrase “as necessary” is retained because the Transmission Operator is not expected to always operate or direct the actions of a Generator Operator. This allows the TOP to intervene as necessary to avoid system events or instances of high or low voltage. Also, since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.

Santee Cooper
Rene' Free

1. The rationale statement for R1 of VAR-001 says that it, "will allow each Transmission Operator (TOP) to establish its own policies and procedures," regarding voltage schedules and tolerance bands. This wording does nothing to prevent specifying an unreasonably-tight bandwidth (e.g. +/- 0.5%). We suggest that R1.1 end as follows, "…voltage schedules along with associated tolerance bands of not less than 1.5% of the schedule voltage unless technically justified." There may be some resistance to making the standard prescriptive, but it's not a burdensome requirement.
2. VAR-002, R5 should be revised to state; "For generator step-up and auxiliary transformers with nominal primary voltages equal to the generator terminal voltage:" This is to clarify that R4 is N/A to startup transformers and other station auxiliary transformers connected to a HV bus at a plant.

Response: Thank you for your comments. The industry could not reach a consensus on a minimum tolerance band, and some TOPs provided feedback that some tolerance bands are very narrow due to the area's voltage constraints. Also, since VAR-002 did not pass successive ballot, so the VAR SDT will revisit the entire standard before posting it for another 45-day comment/ballot.

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.
3. Draft standard posted for an additional comment and ballot from November 15, 2013 to November 26, 2013.

Description of Current Draft

This is the third posting of the proposed draft standard. This proposed draft standard will be posted for a 10-day final ballot.

Anticipated Actions	Anticipated Date
Additional 45-Day Comment Period with Ballot	October/November 2013
Final Ballot	December 2013
NERC Board of Trustees Adoption	February 2014
Filing to Applicable Regulatory Authorities	February 2014

Version History

Version	Date	Action	Change Tracking
1	6/18/2007	Initial Standard is FERC approved	
2	1/10/2011	FERC approved added LSEs and Controllable Load to the standard.	
3	6/20/2013	WECC Variance is approved by FERC	

Definitions of Terms Used in the Standard

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

None.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4
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

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.

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 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 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

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.

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 Planning]*

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

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.

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 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 instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

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.

R4. The Transmission Operator shall specify the criteria that will exempt generators from: 1) 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) 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.

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.

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 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.

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.

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 1 through 6 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 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 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 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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
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: Medium] [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.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.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.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.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.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.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.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.
3. ~~2.~~3. Draft standard posted for an additional comment and ballot from November 15, 2013 to November 26, 2013.

Description of Current Draft

This is the ~~second~~ third posting of the proposed draft standard. This proposed draft standard will be posted for a ~~45~~10-day ~~formal comment period and parallel~~final ballot.

Anticipated Actions	Anticipated Date
Additional 45-Day Comment Period with Ballot	October/November 2013
Final Ballot	December 2013
NERC Board of Trustees Adoption	~~December~~ February 201~~3~~4
Filing to Applicable Regulatory Authorities	~~December~~ February 201~~3~~4

Version History

Version	Date	Action	Change Tracking
1	6/18/2007	Initial Standard is FERC approved	
2	1/10/2011	FERC approved added LSEs and Controllable Load to the standard.	
3	6/20/2013	WECC Variance is approved by FERC	

Definitions of Terms Used in the Standard

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

None.

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in ~~r~~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

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 ~~must~~ 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.

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 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) ~~and associated tolerance bands~~ 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 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

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 ~~is now required~~ would be performed pursuant to the SOL methodology developed under~~in~~ 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.

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 Planning]*

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

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.

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 Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as ~~needed~~ necessary in Real-time. This may include ~~directions~~ instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

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.

R4. The Transmission Operator shall specify the criteria that will exempt generators from: ~~compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements~~ 1) 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 ~~generating unit~~generator in its area that is exempt from: 1) 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.

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.

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~~ 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 Reactive Power schedule (which is either a range or a target value with an associated tolerance band) ~~and associated tolerance bands~~ 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)~~and 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)~~and 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. ~~The evidence shall include written records, email, or voice recordings.~~

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)~~ and associated tolerance band~~. ~~The evidence shall include written records, email, or voice recordings.~~

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) ~~and associated tolerance bands~~ within 30 days of receiving a request by a Generator Operator.

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.

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 1 through ~~4~~ 6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

~~As defined in the NERC Rules of Procedure,~~ "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 Planning**	**High**	N/A	N/A	N/A	The Transmission Operator ~~has~~does not specif~~y~~~~ied~~ a system voltage schedule (which is either a range or a target value with an associated tolerance band)~~and associated tolerance bands~~.
R2	**Real-time Operations, Same-day Operations, and Operational 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 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.
R5	**Operations Planning**	**Medium**	N/A	The Transmission ~~Operator~~ Operator does not provide~~s~~ 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~~s~~ voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band ~~to~~) to ~~some, but not~~ 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) ~~and tolerance bands~~ to any Generator Operators.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Or The Transmission Operator ~~did~~ 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).
R6	**Operations Planning**	**Lower**	The Transmission Operator does not provide ~~E~~either the technical justification or timeframe for changing generator step-up tap settings~~are not provided~~.	N/A	N/A	The Transmission Operator does not provide ~~Neither~~ the technical justification ~~nor~~ and the timeframe for changing generator step-up tap settings ~~are provided.~~.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R~~3~~4 and R~~4~~5. Please note that Requirement R~~3~~4 is deleted and R~~4~~5 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: Medium] [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.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.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.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.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.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.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.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001-4

Approvals Required
VAR-001-4 – Voltage and Reactive Control

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Transmission Operators (VAR-001-4)

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4shall 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, VAR-001-4 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.

Justification
Because VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements, the Transmission Operators need a quarter to prepare documentation. Additionally, the Transmission Operators that do not already provide tolerance bands with voltage schedules will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements
VAR-001-3 will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 in the particular jurisdiction in which the new standard becomes effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001-4 ~~and VAR-002-3~~

Approvals Required
VAR-001-4 – Voltage and Reactive Control
~~VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules~~

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

~~Generator Operators (VAR-002-3)~~

~~Generator Owners (VAR-002-3)~~

Transmission Operators (VAR-001-4)

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 ~~and VAR-002-3 – All requirements~~ 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, VAR-001-4 ~~and VAR-002-3~~ 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.

Justification

~~The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since~~ Because VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements, the Transmission Operators need a quarter to prepare documentation. ~~The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for~~ Additionally, the Transmission Operators that do not already provide tolerance bands with voltage schedules ~~, those Transmission Operators~~ will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 ~~and VAR-002-2b~~ will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 ~~and VAR-002-3~~ in the particular jurisdiction in which the new standard~~s are becoming~~ becomes effective.

Compliance Operations

Draft Reliability Standard Compliance Guidance for VAR-001-4 and VAR-002-3
October 21, 2013

Introduction

The NERC Compliance department (Compliance) worked with the VAR standard drafting team (SDT) to review the proposed standards VAR-001-4 and VAR-002-3. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the VAR SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

VAR-001 and VAR-002 Questions

Question 1

How will compliance determine if sufficient reactive resources were scheduled as part of VAR-001-4 Requirement R2?

Compliance Response to Question 1

For VAR-001-4 Requirement R2, an auditor would review the studies that a TOP used to schedule resources to see that the studies show whether new resources should be brought online, or if the resources online are sufficient to regulate voltage levels. An auditor may observe a TOP reviewing the study and scheduling live and may pull samples from various time periods to determine whether a TOP scheduled resources as required in the study.

Question 2

Is it clear that VAR-001-4 Requirement R4 allows for exemptions, for any duration, from: 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements?

Compliance Response to Question

It is clear that VAR-001 Requirement R4 allows for any combination of exemptions for generator operators from 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements, as long as the

exemption meets the criteria specified by the TOP. An auditor will not look for any pre-authorization from the TOP; rather an auditor will verify that the generator operator has met the criteria set forth by the TOP.

Question 3

Tolerance bands apply to a set voltage or Reactive Power number with a +/- percentage as the tolerance band. The voltage range or Reactive Power range is a high and low number that a Generator Operator is expected to operate within for reliability purposes. With regard to VAR-001-4 Requirement R5, is it clear that when a voltage range or Reactive Power range is provided as a schedule, a tolerance band is not expected to also be provided?

Compliance Response to Question 3

Yes, it is clear based on VAR-001-4 Requirement R5 that a voltage or Reactive power schedule can be either: 1) a target number with a tolerance band, OR 2) a voltage or Reactive Power range to operate within. An auditor would not expect to see a tolerance band provided with an operating range for voltage or Reactive Power.

Question 4

With regard to VAR-002-3, will generators receive a violation for instances where a system event is affecting system voltage, but the generators made the appropriate conversions and set the AVRs to meet the original schedule provided by the TOP?

Compliance Response to Question 4

No, the generator operators can only be responsible for maintaining the schedule provided by the TOP based on existing facility equipment. In the event that a generator operator does not have the equipment to have visibility of high-side system voltage, the GOP will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the GOP does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the generator operator is non-compliant. However, if the TOP provides a new directive or schedule, the GOP is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the generator operator is expected to comply pursuant to VAR-002-3.

Question 5

Related to VAR-002-3, generators can monitor voltage on either the low side and high side of the GSU (depending on equipment limitation) and the “number” being monitored by the Generator will not always equate to the number provided by the TOP. Is it clear that VAR-002 Requirement R2, part 2.3 only wants a conversion of the schedule provided to the number monitored? Is it clear that there should not be a violation if the schedule does not match the number being monitored on the low side as long as there is a documented conversion?

Compliance Response to Question 5

The Generator should be able to provide documentation that identifies the “number” being monitored and the calculation demonstrating how the “number” equates to the schedule provided by the TOP. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit.

Question 6

VAR-002-3, Requirement R4 was added because generators cannot report a capability change until they are aware of the change. The currently enforceable standard requires a notification as soon as the capability change occurs; however, many times the change occurred well before the generators were aware of the problem. Is it clear that VAR-002-3 Requirement R4 is only violated after the generator is made aware of the change?

Compliance Response to Question 6

It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the reactive capability change. An auditor will ask an entity for evidence to demonstrate when it became aware of the change in reactive capability. This will not be purely subjective; there are technical instances where it will be clear that an entity would have been made aware of the change in reactive capability. For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

VAR Mapping Document
Transition of VAR-001-3

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R1	Requirement R1	This requirement is duplicated in other standards, and the new requirement has been simplified to require the specification of the voltage and Reactive Power schedules and associated tolerance bands. A new part 1.1 has been added to allow for voltage coordination with adjacent TOPs and applicable RCs. In the currently enforceable standards, the TOP-004-2 Requirements R1, R2, and R3 duplicate monitoring and controlling voltage requirements. The same requirements that make the TOP operate within the IROLs and SOLs also require the monitoring and controlling of voltage as a necessary action. The pending TOP-002-3 Requirement R2 and TOP-001-2 Requirements R7 and R9 also cover this function because collectively those requirements mandate: 1) having a plan to operate within IROLs and SOLs and 2) operating within IROLs and SOLs.
VAR-001-3 R2	Requirement R2	The new requirement has been updated to just reflect the scheduling of resources. It eliminates the need for the existing R7, R8, and R9. It also maintains a list of sufficient reactive resources.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R3	Requirement R4	The new requirement has been simplified by removing the need to maintain an exemption list. Instead, the standard focuses on whether the exemption criteria are known and whether a granted exemption was communicated to the applicable Generator.
VAR-001-3 R4	Requirement R5	The new requirements have been updated to allow the TOP to provide the voltage or Reactive Power schedule at either the high side or the low side of the GSU. Also a tolerance band is now required under the new requirement. New parts have also been added to direct a GOP to operate in AVR, to require the TOP to provide notification requirements, and to provide the criteria for developing schedules and tolerance bands upon request.
VAR-001-3 R5	Deleted	This requirement was proposed to be retired in the P81 NOPR. Therefore, pending a final rulemaking on P81, this requirement has been deleted.
VAR-001-3 R6	Deleted	This requirement is deleted because the TOP standards require knowing the status of Reactive Power resources. In the pending TOP-006-3 R1 and the currently enforceable TOP-006-2 R1, the TOP and BA must know the status of all generating and transmission resources available for use. Although power system stabilizers are not specifically named in either of the TOP standards, the areas that rely on PSS equipment will require monitoring the PSS status under the data specifications of the TOP standards.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R7	Deleted	This has moved into the new R3.
VAR-001-3 R8	Deleted	This has moved into the new R3.
VAR-001-3 R9	Deleted	See comments for new R2.
VAR-001-3 R10	Deleted	This is duplicative of the pending TOP-001-2 Requirements R9, R10, and R11 before FERC and the Glossary Tv definition which states that IROL and SOL violations must be corrected within 30 minutes. The currently enforceable TOP-004-2 R4 also duplicates this requirement to correct IROLs and SOLs within 30 minutes.
VAR-001-3 R11	Requirement R6	The requirement has been updated to allow for scheduling consultation.
VAR-001-3 R12	Deleted	This requirement was deleted because the EOP standards address taking any corrective action including load-shedding. Also the pending TOP-002-3 Requirement R2 and TOP-001-2 Requirement R11 address the TOP taking corrective actions. The currently enforceable TOP-004-2 R4 also duplicates this requirement to take corrective action.

VAR Mapping Document

Transition of VAR-001-3 ~~and VAR-002-2b~~

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R1	Requirement R1	This requirement is duplicated in other standards, and the new requirement has been simplified to require the specification of the voltage and Reactive Power schedules and associated tolerance bands. A new part 1.1 has been added to allow for voltage coordination with adjacent TOPs and applicable RCs. In the currently enforceable standards, the TOP-004-2 Requirements R1, R2, and R3 duplicate monitoring and controlling voltage requirements. The same requirements that make the TOP operate within the IROLs and SOLs also require the monitoring and controlling of voltage as a necessary action. ~~The pending TOP-002-3 Requirement R2 and TOP-001-2 Requirements R7 and R9 also cover this function because collectively those requirements mandate: 1) having a plan to operate within IROLs and SOLs and 2) operating within IROLs and SOLs.~~

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R2	Requirement R2	The new requirement has been updated to just reflect the scheduling of resources.~~-~~ Scheduling is a more accurate term for TOP operations. It eliminates the need for the existing ~~R7, R8, and~~ R9. It also maintains a list of sufficient reactive resources.
VAR-001-3 R3	Requirement R4	The new requirement has been simplified by removing the need to maintain an exemption list. Instead, the standard focuses on whether the exemption criteria are known and whether a granted exemption was communicated to the applicable Generator. It eliminates the need for the existing R7 and R8.
VAR-001-3 R4	Requirement R5	The new requirements have been updated to allow the TOP to provide the voltage or Reactive Power schedule at either the high side or the low side of the GSU. Also a tolerance band is now required under the new requirement. New parts have also been added to direct a GOP to operate in AVR, to require the TOP to provide notification requirements, and to provide the criteria for developing schedules and tolerance bands upon request.
VAR-001-3 R5	Deleted	This requirement was proposed to be retired in the P81 NOPR. Therefore, pending a final rulemaking on P81, this requirement has been deleted.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R6	Deleted	This requirement is deleted because the TOP standards require knowing the status of Reactive Power resources. In the pending TOP-006-3 R1 and the currently enforceable TOP-006-2 R1, the TOP and BA must know the status of all generating and transmission resources available for use. Although power system stabilizers are not specifically named in either of the TOP standards, the areas that rely on PSS equipment will require monitoring the PSS status under the data specifications of the TOP standards.
VAR-001-3 R7	Deleted	This has moved into the new R3.
VAR-001-3 R8	Deleted	This has moved into the new R3.
VAR-001-3 R9	Deleted	See comments for new R2.
VAR-001-3 R10	Deleted	This is duplicative of the pending TOP-001-2 Requirements R9, R10, and R11 before FERC and the Glossary Tv definition which states that IROL and SOL violations must be corrected within 30 minutes. The currently enforceable TOP-004-2 R4 also duplicates this requirement to correct IROLs and SOLs within 30 minutes.
VAR-001-3 R11	Requirement R6	The requirement has been updated to allow for scheduling consultation.

Standard: VAR-001-4 – Voltage and Reactive Control		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-001-3 R12	Deleted	This requirement was deleted because the EOP standards address taking any corrective action including load-shedding. ~~Also the pending TOP-002-3 Requirement R2 and TOP-001-2 Requirement R11 address the TOP taking corrective actions.~~ The currently enforceable TOP-004-2 R4 ~~also~~ duplicates this requirement to take corrective action.

~~Standard: VAR-002-3 – Capacity Benefit Margin~~		
~~**Requirement in Approved Standard**~~	~~**Transitions to the below Requirement in New Standard or Other Action**~~	~~**Description and Change Justification**~~
~~VAR-002-2b R1~~	~~Requirement R1~~	~~The requirement has been modified to allow for testing and exemptions for other AVR modes when necessary.~~
~~VAR-002-2b R2~~	~~Requirement R2~~	~~The new requirement has been updated to allow for the TOP to define notification requirements. The requirement also adds parts to allow for the conversion of a high side schedule to a low side number for monitoring purposes.~~
~~VAR-002-2b R3~~	~~Requirement R3 and R4.~~	~~The old requirement has been broken into two requirements: 1) one for AVR/PSS status, and 2) one for reactive capability. Both allow 15 minutes to correct an issue before having to notify the TOP.~~
~~VAR-002-2b R3~~	Requirement ~~R4~~R5	~~The requirement has not been modified.~~The original sub-requirement 4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed because other data specifications in MOD-10-0 requirement R2 duplicate this requirement.
~~VAR-002-2b R4~~	~~Requirement R5~~	~~The requirement has not been modified.~~

Formatted: Highlight

DRAFT Reliability Standard Audit Worksheet[1]

VAR-001-4 – Voltage and Reactive Control

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X		
R2													X		
R3													X		
R4													X		
R5													X		
R6													X		

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

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.

1.1. Each Transmission Operator shall provide a copy of the voltage schedules and associated tolerance bands 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 were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[3]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M1.
Documentation of request made per Part 1.1 from Reliability Coordinator and/or adjacent Transmission Operators, if applicable and requested by auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

[3] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R1
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R1) Review evidence provided and ensure it meets the requirements outlined in Requirement R1.
	(Part 1.1) Examine evidence to verify that voltage schedules were provided within 30 days of request per Part 1.1.

Note to Auditor: Auditors, at their discretion and based on the risk of the entity's compliance with this requirement to the BES, may communicate with Balancing Authorities and other Transmission Operators to determine if data requests were made of the entity. Auditors may also accept entity assertions regarding whether data requests made.

Entity assertions that no data requests were made do not have to be in writing.

Auditor Notes:

R2 Supporting Evidence and Documentation

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.

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

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[4]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review the studies/assessments that entity used to schedule resources to determine that the studies show whether new resources should be brought online, or if the resources online are sufficient to regulate voltage levels. Auditors should verify that actual scheduling reflected the results of the studies/assessments.

[4] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough instances, per above, to gain reasonable assurance that entity is complying with Requirement R2.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary.

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as needed in Real-time. This may include directions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity operates or directs devices to regulate transmission voltage and reactive flow as necessary, if the entity has such documents.
Evidence as outlined in M3 as requested by auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R3
This section to be completed by the Compliance Enforcement Authority

	Review evidence to understand how entity operates or directs devices to regulate transmission voltage and reactive flow as necessary. Auditors may sample system events or other instances of voltage irregularities to verify that operations or directions occurred as required per Requirement R2.
Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough events or other instances of voltage irregularities, per above, to gain reasonable assurance that entity is complying with Requirement R2.	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. The Transmission Operator shall specify the criteria that will exempt generators from compliance with the requirements defined in Requirement R5, part 5.1, and any associated notification requirements.

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 generating unit in its area that is exempt from: 1) 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.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[6]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review evidence and note existence of exemption criteria per Requirement R4. For a sample of exempted generators, verify that exemption was granted in accordance with criteria.

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	(Part 1.1) For a sample of exempted generators, ensure exempted generator was notified.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough generators, per above, to gain reasonable assurance that entity is complying with Requirement R4.

Requirement R4 allows for any combination of exemptions for generator operators from 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements, as long as the exemption meets the criteria specified by the entity. An auditor will not look for any pre-authorization from the entity; rather an auditor will verify that the generator operator has met the criteria set forth by the entity.

Auditor Notes:

R5 Supporting Evidence and Documentation

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.

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (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.

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules and associated tolerance bands 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 and tolerance band.

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule and 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. The evidence shall include written records, email, or voice recordings.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule and associated tolerance band. The evidence shall include written records, email, or voice recordings.

For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules and associated tolerance bands within 30 days of receiving a request by a Generator Operator.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M5.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R5
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Verify existence of voltage or Reactive Power schedule and that it meets the requirements of Requirement R5.
	(Part 5.1) For a sample of Generator Operators, verify voltage or Reactive Power schedule was provided

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	per Part 5.1.
	(Part 5.2) For a sample of Generator Operators, verify the notification requirements for deviations from the voltage or Reactive Power schedule was provided per Part 5.2.
	(Part 5.3) For a sample of Generator Operators, verify criteria was provided as requested per Part 5.3.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough notifications, per above, to gain reasonable assurance that entity is complying with Requirement R5.

It is clear based on VAR-001-4 Requirement R5 that a voltage or Reactive power schedule can be either: 1) a target number with a tolerance band, Or 2) a voltage or Reactive Power range to operate within. An auditor would not expect to see a tolerance band provided with an operating range for voltage or Reactive Power.

Auditor Notes:

R6 Supporting Evidence and Documentation

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.

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.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

See M6.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-001-4, R6

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Understand entity's procedures concerning coordinating tap settings with Generator Owners per Requirement R6.
	For a sample of Generator Owners, verify tap setting changes were executed per Requirement R6.
Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound, only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough tap setting communications, per above, to gain reasonable assurance that entity is complying with Requirement R6.	

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/07/2013	NERC compliance, Standards	New Document

Violation Risk Factor and Violation Severity Level Justifications

VAR-001-4 – Voltage and Reactive Control

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in VAR-001-4 – Voltage and Reactive Control. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project. A copy of the standard with the associated VRFs and VSLs is available here.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the

Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification – VAR-001-4 Requirement R1	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is necessary because this requirement ensures that a system voltage schedule is created to ensure system stability.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: This High VRF is consistent with the Blackout Report because Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement. The sub-part within Requirement R1 is consistent and considered a High VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be consistent with the VRFs for other standards (e.g., TOP, FAC, etc.) addressing operating within the appropriate limits.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because voltage instability will cause “Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.”
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-001-4 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guideline, this VSL acknowledges the criticality of this requirement and whether or not a system voltage schedule was created.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL because this is a new requirement, and it only has a "severe" VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL is consistent with the corresponding requirements.

Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – VAR-001-2 Requirement R2	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is consistent with the NERC VRF definition. Requirement R2 focuses on ensuring there are enough reactive resources online to regulate voltage levels, and a High VRF represents the criticality of making sure the system resources are adjusted to meeting normal and Contingency conditions.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: This High VRF is consistent with the Blackout Report because Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System. Therefore, ensuring the proper resources are online for voltage support warrants a High VRF.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement R2; therefore, it is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because scheduling resources is critical to preventing a system operating limit, this VRF is drafted to be consistent with other standards (e.g., TOP, FAC, etc.) that address operating within the appropriate limits.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs:

	This VRF is consistent with the NERC Definition because not scheduling enough resources to support system conditions will cause "Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures."
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the requirement to reflect a lower risk level.

VSL Justification – VAR-001-4 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

"Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-001-4 Requirement R3	
Proposed VRF	**High**
NERC VRF Discussion	This requirement warrants a High VRF and is consistent with the NERC definition because this requirement represents a critical step that TOPs should take in order to avoid an SOL violation in Real-time.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: This High VRF is consistent with the Blackout Report because Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System. Therefore, ensuring that the TOP directs the Real-time devices as necessary to regulate voltage and reactive flow warrants a High VRF.

FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because directing other Real-time devices for voltage and reactive flows is critical to preventing a system operating limit, this VRF is drafted to be consistent with other standards (e.g., TOP, FAC, etc.) that address operating within the appropriate limit.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not directing Real-time operation of devices as necessary could directly cause "Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures."
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-001-4 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.

FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for “Binary” Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-001-4 Requirement R4	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is Lower because it focuses on whether a TOP has created an exemption criteria. The Lower VRF is warranted because many entities will not have any exemptions allowed generators within their system. Additionally, a violation of this requirement would not adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: This VRF is consistent with the Blackout Report because although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, a violation of the requirements to have exemption criteria would result in the GOPs being held to a more stringent performance requirement and is unlikely to severely affect the reliability of the bulk Power System. Therefore, a lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The sub-part within Requirement R4 is consistent with R4 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Other standards do not address exemptions from 1) voltage schedules; 2) AVR settings; or 3) any associated notifications.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because if the GOP is not exempted, a higher performance expectation maintained for GOPs. This does more to protect against events that could cause “Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.”
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a Lower risk level.

VSL Justification – VAR-001-4 Requirement R4	
NERC VSL Guidelines	This VSL is consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3:	The proposed VSL is worded consistently with the corresponding requirement.

Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-001-4 Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement is a Medium because even if a TOP does not provide the voltage or Reactive Power schedules to all GOPs, the TOP is still monitoring the system and will direct the GOPs within an area to provide voltage support as necessary.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: This VRF is consistent with the Blackout Report because although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the TOP standards and Requirements R1-4, still require the TOP to monitor voltage to operate within System Operating Limits. Therefore, a Medium VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The parts within Requirement R5 are consistent with Requirement R5 and is considered a Medium VRF.

FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: As explained in Guideline 1, this requirement is consistent with other standards, namely TOP standards.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation "could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System." However, due to the TOP standards, a violation is unlikely to like to a lead "to Bulk Electric System instability, separation, or cascading failures."
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-001-4 Requirement R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2:	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties.

Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-001-4 Requirement R6

Proposed VRF	Lower
NERC VRF Discussion	This requirement ensures there is coordination for making TOP-directed tap setting changes. A violation of this requirement would not lead to a system event, but the coordination must happen in order for a TOP to know when a generator is going offline. The proper tap settings also ensures Max VAR capability of a unit is maintained.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: This VRF is consistent with the Blackout Report because although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement is aimed at improving the max VARs put into the system. If this requirement were violated, the system would still operate at the level it was prior to making the tap changes.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement R6, and a TOP would still be monitoring the system in order to prevent a system event. Therefore, this requirement is consistent and considered a Medium VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This requirement is not addressed by other standards.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation "could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System." However, due to the TOP standards, a violation of this requirement alone is unlikely to like to a lead "to Bulk Electric System instability, separation, or cascading failures."
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-001-4 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3:	The proposed VSL is worded consistently with the corresponding requirement.

Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

DRAFT-Consideration of Issues and Directives

Project 2013-04 – Voltage and Reactive Control

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
Summary of Directives from FERC: **1.** VAR-001: FERC ordered that the standard be developed to: (1) expand the applicability to include reliability coordinators and LSEs; (2) include detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identifies acceptable margins above the voltage instability points; (3) include Requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available, to assist real-time operations, for areas susceptible to voltage instability; (4) include controllable load among the reactive resources to satisfy reactive requirements and (5) addresses the power factor range at the interface between LSEs and the transmission grid. **2.** VAR-001: FERC clarified that voltage schedules must have a technical basis and remanded an interpretation of VAR-001 back to NERC for reconsideration. **3.** VAR-002: FERC directed NERC to consider Dynegy's suggestions to improve the standard by providing more detailed and definitive requirements for establishing time frames associated with an incident of non-compliance.		
Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and	Order No. 693, P 1855	FERC recently issued a Notice of Proposed Rulemaking on the IRO family of standards.[1] Although FERC recommended a remand of the IRO filing, the monitoring role of the Reliability

[1] *Monitoring System Conditions - Transmission Operations Reliability Standard Transmission Operations Reliability Standards Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (2013).

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.		Coordinator is best addressed in the IRO standards generally. Therefore, this directive will be addressed by a future IRO project.
The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	Order No. 693, P 1858	This directive has been met, and is effectively retired. This directive has already been addressed and reviewed by FERC in a prior version VAR-001-2.[2] However, the applicable requirement (R5 of the currently effective VAR-001-3) that initially addressed this directive has been removed from the VAR standards due to overlap with the *pro forma* Open Access Transmission Tariff ("OATT").[3] Thus, this directive is no longer needed for reliability and should be withdrawn or retired.
In the NOPR, the Commission asked for comments on acceptable ranges of net power factor at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions... The Commission believes that Reliability Standard VAR-001-1 is an appropriate place for the ERO to take steps to address these concerns by setting out requirements for transmission owners and LSEs to maintain an appropriate power factor range at their interface. **We direct the ERO**	Order No. 693, P 1861	This directive is no longer needed for reliability and should be withdrawn. Power factor ranges/requirements are established by contract, and to include such ranges/requirements in the VAR standard would be duplicative. The TPL-001-4 has now been approved and will address requirements for power factors. TPL-001-4, Requirement R1, part 1.1.4 requires system models to include Real and reactive Load forecasts. These two inputs in the TOP's models ultimately provide the appropriate power factors that should be maintained.

---

[2] *See* FERC letter order, *NERC Petition for Approval of Proposed Modifications to Reliability Standards BAL-002-1; EOP-002-3; FAC-002-1; MOD-021-2; PRC-004-2; and VAR-001-2,* 134 FERC ¶ 61,015 (2011).
[3] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards,* Order No. 788, 145 FERC ¶ 61,147 (2013).

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk- Power System.		In addition, the FAC-001-0 standard requires Transmission Owners (TOs) to set interconnection requirements including "Voltage, Reactive Power, and <u>power factor control</u>" (emphasis added). Thus, the power factor controls and requirements are outlined as part of the interconnection studies/process. Finally, as markets have matured the RTO's have addressed the reliability issues regarding wholesale LSE's through various governance agreements. These agreements speak to the reliable planning, operation, and coordination between the BPS and LSE's.
We direct the ERO to include APPA's concern in the Reliability Standards development process. We note that transmission operators currently have access to data through their energy management systems to determine a range of power factors at which load operates during various conditions, and **we suggest that the ERO use this type of data as a starting point for developing this modification.**	Order No. 693, P 1862	The directive has been addressed by the VAR SDT, and APPA's concerns were discussed early in Project 2013-04. In Order No. 693 APPA stated, "it may be difficult to reach an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors. APPA further states that system power factors will be affected by the transmission infrastructure used to supply the load."[4]

[4] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶31,242 at P 1861, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		As stated above, the VAR SDT determined the power factor will be addressed by interconnection agreements, the OATT, and other standards. In light of how the directives for PP 1858 and 1863 are addressed, the VAR SDT determined the appropriate power factor range is addressed through the OATT and the interconnection process. Therefore, the VAR SDT determined that it was not necessary to add VAR requirements to access power factor data because that would be duplicative, and FERC determined these types of requirement are not needed for reliability, as stated in Order No. 788 which approved certain P81 retirements.[5]
The Commission expects that the appropriate power factor range developed for the interface between the bulk electric system and the LSE from VAR-001-1 would be used as an input to the transmission and operations planning Reliability Standards. The range of power factors developed in this Reliability Standard provides the input to the range of power factors identified in the modifications to the TPL Reliability Standards.	Order No. 693, P 1863	The Commission clarified that this is not a directive to change or modify a standard.[6]
In the NOPR, the Commission expressed concern that the technical requirements containing terms such as	Order No. 693, P1868	This directive on established limits is being addressed in an equally effective and efficient manner through the TOP and FAC

[5] *See* Order No. 788.

[6] *Id.* at Attachment A.

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
"established limits" or "sufficient reactive resources" are not definitive enough to address voltage instability and ensure reliable operations. To address this concern, the NOPR proposed directing the ERO to modify VAR-001-1 to include more detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. **We will keep this direction, and direct the ERO to include this modification in this Reliability Standard**.		family of standards. After Order No. 693 was issued, several standards were approved by FERC providing specific requirements on "established limits" and associated margins. FAC-011 and FAC-014 both address SOLs which by definition must include both voltage stability ratings and system voltage limits. An SOL is the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). [7] Further, FAC-014-2 Requirement R2 demands "[t]he Transmission Operator shall establish SOLs (as directed by its

[7] *See NERC Glossary of Terms Used in Reliability Standards,* available at *http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." FAC-011-2 Requirement R2 states "[t]he Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1. In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages. R2.2. Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur." (emphases added). FAC-011-2, R3 states: "The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum,

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		a description of the following, along with any reliability margins…" (emphasis added). Although FAC standards require the establishment and criteria of SOLs, the TOP standards require operations within SOLs and IROLs. The currently enforceable TOP-002-2.1b requires that "Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs)." TOP-004-2 R1 states "Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs)." Thus, the TOP and FAC standards provide sufficient details on established limits and acceptable margins for voltage by providing vehicles for monitoring and operating within SOLs and IROLs. If a system event were to occur due to voltage, the TOP and FAC standards would be the appropriate place for a violation because a limit would have been violated. With regard to the directive on sufficient reactive resources, VAR-001 R2 has been modified to state the TOP will "schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load." As explained in the rationale for the new requirement ensures sufficient reactive resources are online or scheduled to regulate voltage levels. The old requirement used the term "acquire" instead of schedule, and there was industry confusion on how to acquire sufficient reactive resources.
We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for "established limits" and "sufficient reactive resources." **Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process.**	Order No. 693, P 1869	The Commission clarified that this is not a directive to change or modify a standard.[8]
In response to the concerns of APPA, SDG&E and EEI on the availability of tools, the Commission recognizes that transient voltage stability analysis is often conducted as an offline study, and that steady-state voltage stability analysis can be done online. The Commission clarifies that it does not wish to require anyone to use tools that are not validated for real-time operations. Taking these comments into consideration, the Commission clarifies its	Order No. 693, P 1875	Analytical tools or online techniques in general will be addressed in Project 2009-02, Real-time Monitoring and Analysis Capabilities. Therefore, this directive will be addressed in that project. Further, the VAR SDT determined that the Commission is not requiring TOPs to purchase new online models or to implement tools that will not adequately study a TOP's reactive power requirements. The VAR SDT also

[8] *See* Order No. 788 at Attachment A.

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
proposed modification from the NOPR. For the Final Rule, **we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations. The ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.**		determined that the most reliable models are the ones proven over time to correctly model the system. Further, the VAR SDT also determined the TOP standards require periodic voltage stability analysis. The currently enforceable standards: TOP-004-2 and TOP-006-2 require actively monitoring voltage in order to operate within SOLs.
The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system. Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1. **While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to**	Order No. 693, P 1879	NERC addressed this directive in a prior version of the VAR standard, but as mentioned above, examples of sufficient reactive resources including controllable load are listed in VAR-001 R2.[9]

[9] *supra* at note 2.

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.		
Dynegy has suggested an improvement to Reliability Standard VAR-002-1, and NERC should consider this in its Reliability Standards development process.	Order No. 693, P 1885	Dynegy stated that VAR-002-1 should be modified to require detailed and definitive requirements when defining the timeframe associated with an “incident” of non-compliance. The VAR SDT, NERC staff, and industry participants could not agree on an appropriate number for creating a non-compliance window for the continent. Instead, VAR-001 was modified to require TOPs to create notification requirements for their GOPs in VAR-001-4 Requirement 5, part 5.2. The TOPs can then tailor their notification requirements based on their area’s reliability needs/voltage constraints.
The Commission remands to the ERO the proposed interpretation of VAR-001-1, Requirement R4 and directs the ERO to revise the interpretation consistent with the Commission’s discussion below.	Order No. 724, P 47.	P 49 of Order No. 724 explains this directive by stating “the Commission adopts its NOPR proposal, and finds that a voltage schedule should reflect sound engineering, as well as operating judgment and experience. The Commission remands NERC’s proposed VAR-001-1, Requirement R4 interpretation, in order

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		that NERC may reconsider its interpretation consistent with this order."[10] NERC staff and TOPs expressed concern that having to justify a schedule could provide a forum for disputing voltage schedules in general. This could harm reliability if GOPs were permitted to not implement a schedule until there was consensus on the technical merits of a voltage schedule. Therefore, in order to maintain a TOPs authority for setting schedules, the VAR SDT determined the standard should require sharing study data for how a voltage schedule was determined. The VAR SDT determined that in order to show voltage schedules reflect sound engineering and judgment, a TOP should provide the criteria for developing schedules and tolerance bands when requested by a GOP. This is reflected in VAR-001-4 Requirement 5, part 5.3. This requirement allows the GOP to understand the technical basis for a voltage schedule, but it does not create a vehicle for the GOPs to approve the voltage schedule.

[10] *Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, 127 FERC ¶ 61,158 at P 49 (2009).

NERC

Voltage and Reactive Control		
Issue or Directive	**Source**	**Consideration of Issue or Directive**

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Update

Project 2013-04 Voltage and Reactive Control
VAR-001-4

Final Ballot Now Open through December 23, 2013

Now Available

It has come to NERC's attention that an administrative error resulted in incorrect votes being carried forward for the VAR-001-4 final ballot that opened on December 11, 2013. The final ballot for VAR-001-4 is being restarted today with the appropriate votes carried forward and will end on Monday, December 23, 2013. Anyone who has logged in during the incorrect final ballot period to change their vote will need to log in again to revote in this ballot. We recognize that this ballot now closes the Monday of a holiday week and apologize for the inconvenience.

As this final ballot needed to be restarted due to the administrative error, the following two additional clarifying changes were made to the standard:

- **The language in Requirement R4 regarding criteria for generator exemptions was clarified to match the language in the measure.**
- **Requirement references in the WECC Regional Variance were updated to match the corresponding requirements in VAR-001-4.**

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

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-001-4

Final Ballot Now Open through December 20, 2013

Now Available

A final ballot for **VAR-001-4** is open through **8 p.m. Eastern on Friday, December 20, 2013.**

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

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-001-4 and VAR-002-3

Final Ballot Results

Now Available

A final ballot for **VAR-001-4** concluded at **8 p.m. Eastern on Monday, December 23, 2013.**

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballots.

Standard	Quorum /Approval
VAR-001-4	84.34% / 75.35%

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

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

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

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results

Ballot Name:	Project 2013-04 Voltage and Reactive Control VAR-001-4 _
Ballot Period:	12/13/2013 - 12/23/2013
Ballot Type:	Final Ballot
Total # Votes:	334
Total Ballot Pool:	396
Quorum:	**84.34 % The Quorum has been reached**
Weighted Segment Vote:	75.35 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	106	1	57	0.695	25	0.305	0	8	16
2 - Segment 2	9	0.9	7	0.7	2	0.2	0	0	0
3 - Segment 3	86	1	48	0.727	18	0.273	0	8	12
4 - Segment 4	30	1	15	0.789	4	0.211	0	7	4
5 - Segment 5	98	1	42	0.656	22	0.344	0	13	21
6 - Segment 6	52	1	28	0.683	13	0.317	0	4	7
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.7	6	0.6	1	0.1	0	1	0
Totals	**396**	**7.1**	**208**	**5.35**	**85**	**1.75**	**0**	**41**	**62**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Electric Power	Paul B Johnson		
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Abstain	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Abstain	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Negative	

1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	SUPPORTS THIRD PARTY COMMENTS
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Abstain	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Western Area Power Administration	Lloyd A Linke	Negative	COMMENT RECEIVED
				SUPPORTS

1	Xcel Energy, Inc.	Gregory L Pieper	Negative	THIRD PARTY COMMENTS
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Negative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Negative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Abstain	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia System Operations Corporation	Scott McGough	Abstain	
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
				SUPPORTS

3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	THIRD PARTY COMMENTS
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	SUPPORTS THIRD PARTY COMMENTS
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	

4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Arizona Public Service Co.	Scott Takinen	Negative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Abstain	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Negative	SUPPORTS THIRD PARTY COMMENTS - FMPA
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Abstain	- (SERC OC)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Abstain	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lafayette Utilities System	Jamie B Webb	Affirmative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	

5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Abstain	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing		
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Bonnie Marino-Blair	Negative	COMMENT RECEIVED
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY COMMENTS
5	USDI Bureau of Reclamation	Erika Doot	Negative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Negative	
5	Vandolah Power Company L.L.C.	Douglas A. Jensen	Abstain	
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS

6	AEP Marketing	Edward P. Cox		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Negative	COMMENT RECEIVED
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS
6	FirstEnergy Solutions	Kevin Querry	Abstain	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	

8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.
3. Draft standard posted for additional comments and ballot from October 11, 2013 to November 26, 2013.

Description of Current Draft

This is the third posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
Additional 45-Day SAR Comment Period with Ballot	February/March
Final Ballot	April 2014
NERC Board of Trustees Adoption	May 2014
Filing to Applicable Regulatory Authorities	May 2014

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

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

None.

A. Introduction

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

2. **Number:** VAR-002-3

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**

   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, VAR-002-3 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

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.

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 the control mode that was instructed by the Transmission Operatorfor 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 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.

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.

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.

[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.

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 document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.

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. Such notifications 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 or capability change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. The 30-minute window should resolve most issues.

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 to 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.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-00202b 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.

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 such change, then to 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]*

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.

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 subpart 4.1.4 (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.

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 transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirement R5 part 5.1.1 through part 5.1.3 within 30 calendar days.

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.

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 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.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The Generator Operator did not have conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator did not maintain voltage or Reactive Power schedule as directed 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.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Operator 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 Operator 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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it cannot comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.
3. Draft standard posted for additional comments and ballot from October 11, 2013 to November 26, 2013.

Description of Current Draft

This is the ~~second~~ third posting of the proposed draft standard. This proposed draft standard will be posted for a 45-day formal comment period and parallel ballot.

Anticipated Actions	Anticipated Date
Additional 45-Day SAR Comment Period with Ballot	~~October/November 2013~~February/March
Final Ballot	~~December 2013~~April 2014
NERC Board of Trustees Adoption	~~December 2013~~May 2014
Filing to Applicable Regulatory Authorities	~~December 2013~~May 2014

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

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

None.

A. Introduction

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

2. **Number:** VAR-002-3

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**

   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, VAR-002-3 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

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.

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 ~~the Generator Operator~~: 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 the ~~automatic voltage~~ 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 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 ~~must~~ 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 ~~it~~ 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.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates ~~the~~ its generator(s) ~~system~~ to ~~maintain~~ provide ~~a~~ voltage ~~schedule~~ 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 ~~shall~~ may monitor voltage ~~based~~ by using ~~on~~ 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.

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 ~~directed~~ provided by the Transmission 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~~ generator is operating in manual control, reactive power capability may change based on stability considerations.

2.2. When ~~directed~~ 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 ~~unit~~ 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 ~~directed~~ provided by the Transmission Operator.

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

For part 2.3, for ~~units~~ Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.

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. Such notifications provide~~d~~ little to no benefit to reliability. ~~Fifteen~~ Thirty (~~15~~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 or capability change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. The 30~~15~~-minute window should resolve most issues.

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 ~~the first 15~~ 30 minutes of such change, then ~~there is no need to~~to 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 ~~the~~ any status change identified in Requirement R3. If the status has been restored within the first ~~15~~ 30 minutes, no notification is necessary~~; therefore, if a status change lasts more than 15 minutes, the GOP must notify its associated Transmission Operator within 30 minutes of when the change first occurred~~.

Rationale for R4:

This requirement has been bifurcated from the ~~earlier~~ prior version VAR-00202b 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 already in non-compliance situations by the time it is known that~~are not aware of a reactive capability change until it has taken place.

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes ~~after~~ 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 ~~the first 15~~ 30 minutes of such change, then ~~there is no need to~~to 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]*

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes ~~of the recognition~~ of becoming aware of a change in reactive capability ~~change identified~~ in accordance with Requirement R4. If the capability has been restored within the first ~~15~~ 30 minutes, no notification is necessary~~; therefore, if a capability change lasts more than 15 minutes, the Generator Operator must notify its associated Transmission Operator within 30 minutes of when the change first occurred~~.

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 ~~amount of~~ VARs ~~produced by a~~ available from that unit can be affected. The ~~original~~ prior version of VAR-002-2b sub~~-requirement~~part 4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed ~~since~~ because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

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 transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirement~~s~~ R5 part 5.1.1 through part 5.1.3 within 30 calendar days.

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 ~~amount of~~ VARs ~~produced by~~ available from that ~~a~~ unit can be affected.

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 ~~Operator~~ Owner cannot comply with the Transmission Operator's specifications, the Generator ~~Operator~~ 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 ~~as identified~~ in accordance with Requirement R6. The Generator ~~Operator~~ 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 ~~as identified~~ 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.

~~As defined in the NERC Rules of Procedure, “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 ~~responsible entity~~Generator Operator did not operate each generator in the automatic voltage control mode or in a different control mode, as instructed by the Transmission Operator, and failed to ~~notify~~ provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	**Real-time Operations**	**Medium**	N/A	N/A	The ~~responsible entity~~Generator Operator did not have conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	The Generator Operator ~~responsible entity~~ did not maintain voltage or Reactive Power schedule as directed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator ~~responsible entity~~ did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator ~~responsible entity~~ did not modify voltage when directed, and the responsible entity did not provide any explanation.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator ~~responsible entity~~ did not make the required notification within 30 minutes.
R4	**Real-time Operations**	**Medium**	N/A	N/A	N/A	The Generator Operator ~~responsible entity~~ did not make the required notification within 30 minutes.
R5	**Real-time Operations**	**Lower**	N/A	N/A	The Generator Operator ~~responsible entity~~ failed to provide ~~to~~ its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement~~s~~ R5 parts 5.1.1 ~~and~~ , 5.1.2, and 5.1.3.	The Generator Operator ~~responsible entity~~ failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement~~s~~ R5 parts 5.1.1, ~~and~~ 5.1.2, and 5.1.3.
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.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Generator ~~Operator~~ Owner failed to perform the tap changes, and the Generator ~~Operator~~ Owner did not provide technical justification for why it cannot comply with the Transmission Operator ~~directive~~specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001-4 and VAR-002-3

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 – All requirements 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, VAR-001-4 and VAR-002-3 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.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements, the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular jurisdiction in which the new standards are becoming effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan
VAR Directives Project

Implementation Plan for VAR-001 and VAR-002

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

~~Reliability Coordinators~~

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 – All requirements ~~- In those jurisdictions where regulatory approval is required, this 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 ~~regulatory approval~~ or as otherwise provided for in a jurisdiction where approval by an~~made effective pursuant to the laws~~ applicable ~~to such ERO~~ governmental authority~~authorities. In those jurisdictions where no regulatory approval~~ is required for a~~, this~~ standard to go into effect. Where approval by an applicable governmental authority is not required, VAR-001-4 and VAR-002-3 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~~approval~~.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements~~a documented policy or procedure for assessments~~,~~;~~ the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular j~~J~~urisdiction in which the new standards are becoming effective.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2013-04 Voltage and Reactive Control (VAR) Revisions

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft VAR-002-3 standard. The electronic comment form must be completed by 8:00 p.m. ET by **April 14, 2014**.

If you have questions please contact Soo Jin Kim via email or by telephone at 404-446-9742.

The project page may be accessed by clicking here.

Background Information

When the first versions of the VAR standards were approved in FERC Order No. 693,[1] the Commission also issued FERC issued several directives with regard to how to improve the standard. Each of the outstanding directives are explained in detail in the technical white paper (see project page).

The informal consensus building for VAR began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, remove paragraph 81 candidates, and implement results-based approaches. A discussion of the ad hoc group's consensus building and collaborative activities are also included in the technical white paper.

Project 2013-04 posted an initial draft for comment and ballot from July 19, 2013 to September 3, 2013. Although the VAR standards did not pass, the industry provided numerous helpful coments, and the standard drafting team made significant revisions based on the stakeholder input. Both VAR-001 and VAR-002 were posted for another comment and ballot from October 11, 2013 to November 26, 2013. VAR-001 successfully passed, but VAR-002 did not receive the necessary votes. This posting is now soliciting comment on the revised VAR-002 standard.

Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

[1] *See Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Question

1. Please provide your comments on the proposed VAR-002-3 below:

Comments:

Compliance Operations

Draft Reliability Standard Compliance Guidance for VAR-001-4 and VAR-002-3
October 21, 2013

Introduction

The NERC Compliance department (Compliance) worked with the VAR standard drafting team (SDT) to review the proposed standards VAR-001-4 and VAR-002-3. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the VAR SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

VAR-001 and VAR-002 Questions

Question 1

How will compliance determine if sufficient reactive resources were scheduled as part of VAR-001-4 Requirement R2?

Compliance Response to Question 1

For VAR-001-4 Requirement R2, an auditor would review the studies that a TOP used to schedule resources to see that the studies show whether new resources should be brought online, or if the resources online are sufficient to regulate voltage levels. An auditor may observe a TOP reviewing the study and scheduling live and may pull samples from various time periods to determine whether a TOP scheduled resources as required in the study.

Question 2

Is it clear that VAR-001-4 Requirement R4 allows for exemptions, for any duration, from: 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements?

Compliance Response to Question

It is clear that VAR-001 Requirement R4 allows for any combination of exemptions for generator operators from 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements, as long as the

exemption meets the criteria specified by the TOP. An auditor will not look for any pre-authorization from the TOP; rather an auditor will verify that the generator operator has met the criteria set forth by the TOP.

Question 3

Tolerance bands apply to a set voltage or Reactive Power number with a +/- percentage as the tolerance band. The voltage range or Reactive Power range is a high and low number that a Generator Operator is expected to operate within for reliability purposes. With regard to VAR-001-4 Requirement R5, is it clear that when a voltage range or Reactive Power range is provided as a schedule, a tolerance band is not expected to also be provided?

Compliance Response to Question 3

Yes, it is clear based on VAR-001-4 Requirement R5 that a voltage or Reactive power schedule can be either: 1) a target number with a tolerance band, OR 2) a voltage or Reactive Power range to operate within. An auditor would not expect to see a tolerance band provided with an operating range for voltage or Reactive Power.

Question 4

With regard to VAR-002-3, will generators receive a violation for instances where a system event is affecting system voltage, but the generators made the appropriate conversions and set the AVRs to meet the original schedule provided by the TOP?

Compliance Response to Question 4

No, the generator operators can only be responsible for maintaining the schedule provided by the TOP based on existing facility equipment. In the event that a generator operator does not have the equipment to have visibility of high-side system voltage, the GOP will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the GOP does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the generator operator is non-compliant. However, if the TOP provides a new directive or schedule, the GOP is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the generator operator is expected to comply pursuant to VAR-002-3.

Question 5

Related to VAR-002-3, generators can monitor voltage on either the low side and high side of the GSU (depending on equipment limitation) and the "number" being monitored by the Generator will not always equate to the number provided by the TOP. Is it clear that VAR-002 Requirement R2, part 2.3 only wants a conversion of the schedule provided to the number monitored? Is it clear that there should not be a violation if the schedule does not match the number being monitored on the low side as long as there is a documented conversion?

Compliance Response to Question 5

The Generator should be able to provide documentation that identifies the “number” being monitored and the calculation demonstrating how the “number” equates to the schedule provided by the TOP. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit.

Question 6

VAR-002-3, Requirement R4 was added because generators cannot report a capability change until they are aware of the change. The currently enforceable standard requires a notification as soon as the capability change occurs; however, many times the change occurred well before the generators were aware of the problem. Is it clear that VAR-002-3 Requirement R4 is only violated after the generator is made aware of the change?

Compliance Response to Question 6

It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the reactive capability change. An auditor will ask an entity for evidence to demonstrate when it became aware of the change in reactive capability. This will not be purely subjective; there are technical instances where it will be clear that an entity would have been made aware of the change in reactive capability. For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

VAR-002 Mapping Document

Transition of VAR-002-2b

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R1	Requirement R1	The requirement has been modified to allow for testing and exemptions for other AVR modes when necessary. This requirement was also modified to allow GOPs to operate in a different control mode as instructed by the TOP.
VAR-002-2b, R2	Requirement R2	The new requirement has been updated to allow for the TOP to define notification requirements. The requirement also adds parts to allow for the conversion of a high side schedule to a low side number for monitoring purposes. Reactive Power schedules have been added for generators that use those schedules, and for consistency purposes “unit” has been changed to “generator”.

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R3	Requirement R3 and R4.	The old requirement has been broken into two requirements: 1) one for AVR/PSS status, and 2) one for reactive capability. Both allow 30 minutes to correct an issue before having to notify the TOP.
VAR-002-2b, R3	Requirement R5	The requirement has been modified to remove the sub-part that requires the GOP to provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." The measure was also modified to add that a GOP must provide the data "within 30 calendar days"
VAR-002-2b, R4	Requirement R6	The requirement has been updated to apply to the same functional entity for the Requirement and sub-part.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

VAR-002 Mapping Document

Transition of VAR-002-2b

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R1	Requirement R1	The requirement has been modified to allow for testing and exemptions for other AVR modes when necessary. This requirement was also modified to allow GOPs to operate in a different control mode as instructed by the TOP.
VAR-002-2b, R2	Requirement R2	The new requirement has been updated to allow for the TOP to define notification requirements. The requirement also adds parts to allow for the conversion of a high side schedule to a low side number for monitoring purposes. Reactive Power schedules have been added for generators that use those schedules, and for consistency purposes "unit" has been changed to "generator".

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R3	Requirement R3 and R4.	The old requirement has been broken into two requirements: 1) one for AVR/PSS status, and 2) one for reactive capability. Both allow ~~15~~ 30 minutes to correct an issue before having to notify the TOP.
VAR-002-2b, R3	Requirement R5	The requirement has ~~not been modified~~been modified to remove the sub-part that requires the GOP to provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." The measure was also modified to add that a GOP must provide the data "within 30 calendar days"~~.~~
VAR-002-2b, R4	Requirement R6	The requirement has ~~not been modified.~~been updated to apply to the same functional entity for the Requirement and sub-part.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	Audit
Names of Auditors:	Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1				X											
R2				X											
R3				X											
R4				X											
R5			X												
R6			X												

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

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 ~~the Generator Operator~~ 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following:

- That the generator is being operated in start-up,[3] shutdown,[4] 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 the ~~automatic voltage~~ 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 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 ~~must~~ 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 ~~it~~ is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

Registered Entity Response to Question (Required):

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this

[3] 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.
[4] 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.
[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M1.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	For instances where entity did not operate a generator in automatic voltage control mode or in a different control mode, as instructed by the Transmission Operator, ensure notification was given to the Transmission Operator in accordance with Requirement R1.

Note to Auditor: Auditors can identify instances where entities did not operate~~d~~ generators ~~outside of~~in automatic voltage control mode, or in a different control mode, as instructed by the Transmission Operator, through their general knowledge of the interconnected transmission system in the entity's area. Auditor knowledge is obtained through activities such as conversations with the entity under audit or the Transmission Operator, and an awareness of events occurring on the interconnected transmission system. In situations where the entity's compliance with this requirement poses little risk to the BES, conversations with other entities, such as Transmission Operators, is most likely not necessary.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[6] (within each generating Facility's capabilities[7]) 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.

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 ~~directed~~ provided by the Transmission Operator.

2.2. When ~~directed~~ 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 ~~unit~~ 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 ~~directed~~ provided by the Transmission Operator.

For part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's ~~directions~~ instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the

[6] 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.

[7] 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~~ generator is operating in manual control, reactive power capability may change based on stability considerations.

~~direction~~instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For part 2.3, for ~~units~~ Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.

Question: As a Generation Operator, have you operated the generator with the AVR out of service?

Registered Entity Response to Question (Required):

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.
Any written policies, procedures or protocols describing how the entity maintains the generator voltage or Reactive Power schedule provided by Transmission Operator, if the entity has such documents.
Generator voltage or Reactive Power schedule provided to entity by Transmission Operator, or entity's record thereof, for timeframes selected by the auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to VAR-002-3, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they maintain the generator voltage or Reactive Power schedule or authorized exemption per Requirement R2.
	Read entity's response to compliance Question above and understand how entity complies with Requirement R2, when they operate a generator with AVR in not in service.
	Select a sample of timeframes during the audit period and have entity walkthrough how they complied with Requirement R2 for those timeframes.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough timeframes, per above, to gain reasonable assurance that entity is complying with Requirement R2.

For part 2.3, the entity should be able to provide documentation that identifies the voltage number being monitored and the calculation demonstrating how it equates to the schedule provided by the Transmission Operator. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit. The entity can only be responsible for maintaining the schedule provided by the Transmission Operator based on existing facility equipment. In the event that an entity does not have the equipment to have visibility of high-side system voltage, the entity will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the entity does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the entity is non-compliant. However, if the Transmission Operator provides a new directive or schedule, the entity is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the entity is expected to comply pursuant to VAR-002-3.

Auditor Notes:

R3 Supporting Evidence and Documentation

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 ~~the first 15~~30 minutes of such change, then the Generator Operator is not required to ~~there is no need to~~ notify the Transmission Operator of the status change.

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of ~~the~~ any status change identified in Requirement R3. If the status has been restored within the first ~~15~~ 30 minutes, no notification is necessary~~; therefore, if a status change lasts more than 15 minutes, the GOP must notify its associated Transmission Operator within 30 minutes of when the change first occurred~~.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[9]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity responds to a status change on AVR, if the entity has such documents. An example of entity's response to a status change on AVR provided by entity, if applicable.
Auditor may select certain instances where entity had a status change on AVR. In such instances, provide associated evidence of awareness and resolution/notification.
Evidence as outlined in M3.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[9] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to VAR-002-3, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they respond to status changes on AVR.
	Review evidence provided to determine if entity responded to status change on AVR in accordance with Requirement R3.
Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough timeframes, per above, to gain reasonable assurance that entity is complying with Requirement R3.	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes after 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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of the recognition of a reactive capability change identified in Requirement R4. If the capability has been restored within the first 15 minutes, no notification is necessary; therefore, if a capability change lasts more than 15 minutes, the Generator Operator must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[10]**:**

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity responds to a change in reactive capability, if the entity has such documents. An example of entity's response to a change in reactive capability provided by entity, if applicable.
Auditor may select certain instances where entity ~~should~~ may have been aware of a status change in reactive capability. In such instances, provide associated evidence of awareness and resolution/notification. See Note to Auditor for additional details.
Evidence as outlined in M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they respond to change in reactive capability.
	Review evidence provided to determine if entity responded to change in reactive capability in accordance with Requirement R4.
Note to Auditor: It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the status change in reactive capability. An auditor will ask an entity for evidence to demonstrate when it became aware of the change. This will not be purely	

[10] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

subjective; there are technical instances (e.g. unit trips, ramping, equipment/AVR failures) where it ~~will be~~is ~~clear~~ likely that an entity ~~would have been~~was made aware of the change in reactive capability. ~~For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.~~

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

5.1. For generator step-up transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirements R5 part 5.1.1 through part 5.1.3.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[11]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M4. Evidence of transmittal of the data could include, but is not limited to, items such as an electronic message or a transmittal letter with the information included or attached.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

[11] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R5
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and reply) to determine if entity responded to information request(s) as required in Requirement R5 within 30 days of receiving a request from associated Transmission Operator.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Transmission Operators to determine if requests for data were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

R6 Supporting Evidence and Documentation

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.

6.1. If the Generator Operator cannot comply with the Transmission Operator's specifications, the Generator Operator 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 as identified in Requirement R6. The Generator Operator 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 as identified in Requirement R6 part 6.1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[12]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M6.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R6
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and response) to determine if entity responded to change(s) as required in Requirement R6.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Transmission Operators to determine if requests for changes to transformer tap positions were made or simply confirm the existence of such requests with the entity under audit.	

[12] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/XX/2013	NERC C~~c~~ompliance, Standards	New Document
2	3/14/2014	NERC Compliance, Standards	Revisions based on changes to underlying Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.   A copy of the standard with the associated VRFs and VSLs is available here.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the

Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification – VAR-002-3 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is necessary because this requirement could affect the stability of the BES, but the requirement itself addresses instances where a GOP will not necessarily operate in with the AVR in different control modes or when the TOP will instruct a GOP to operate in other modes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP control modes are not as critical because the TOP is monitoring the system. The companion requirement to VAR-002-3 (in VAR-001-4) are properly designated with a HIGH VRF to ensure voltage schedules are provided as part of the TOPs plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be the same VRFs for VAR-001-4 Requirement R5. VAR-001-4 Requirement R5 requires the TOP to specify a schedule and notification requirements that the GOP must follow.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a GOP not operating in the proper control mode can affect the BES, but a single violation is unlikely to lead to instability, separation, or cascading failure. This is especially the case since a TOP will also be monitoring for voltage deviations.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guideline, this VSL acknowledges the criticality of this requirement and whether or not a system voltage schedule was created.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL because this requirement only has a "severe" VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirements.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R2 focuses on GOPs maintaining a schedule, but there could be system events that will pull a GOP out of schedule. Also, late at night and early in the morning, the system may experience instances of low or high voltage. This could impact the BES, but a single instance is unlikely to lead to instability, separation, or cascading failure. The sub-requirements also require the GOP to modify the voltage schedule when directed by the TOP.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report lists Reactive Power and voltage control as critical areas where a violation could severely affect the reliability of the Bulk-Power System, there are general times when a GOP will be unable to maintain a voltage schedule due to system condition. These instances occur frequently during the early morning and late at night. The companion requirement to VAR-002-3 (in VAR-001-4) are properly designated

	with a HIGH VRF to ensure voltage schedules are provided as part of the TOP's plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement, including all sub-parts.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be the same VRFs for VAR-001-4 Requirement R5. VAR-001-4 Requirement R5 requires the TOP to specify a schedule and notification requirements that the GOP must follow.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a GOP not maintaining a schedule can affect the BES, but a single violation is unlikely to lead to instability, separation, or cascading failures. This is especially the case since a TOP will also be monitoring for voltage deviations
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

the Current Level of Compliance	
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation,	The proposed VSL is not based on cumulative number of violations.

Not on A Cumulative Number of Violations	

VRF Justification – VAR-002-3 Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement warrants a Medium VRF and is consistent with the NERC definition because this requirement is whether the GOP made the required notifications to the TOP within the appropriate timeframes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP notifications are unlikely to lead to system instability, separation, or cascading failures. This is particularly the case because the TOP is still operating the system to stay within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This VRF is drafted to be consistent with other standards (e.g., BAL) that address making appropriate notifications.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not making the appropriate notifications can impact the grid, but the TOPs are still effectively monitoring the system; thus, instability, separation, or cascading failures are unlikely due to a single violation.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-002-3 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the standard is violated only when a notification is not made to the TOP; therefore, a severe VSL is warranted. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement warrants a Medium VRF and is consistent with the NERC definition because this requirement is whether the GOP made the required notifications to the TOP within the appropriate timeframes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP notifications are unlikely to lead to system instability, separation, or cascading failures. This is particularly the case because the TOP is still operating the system to stay within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This VRF is drafted to be consistent with other standards (e.g., BAL) that address making appropriate notifications.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not making the appropriate notifications can impact the grid, but the TOPs are still effectively monitoring the system; thus, instability, separation, or cascading failures are unlikely due to a single violation.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-002-3 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the standard is violated only when a notification is not made to the TOP; therefore, a severe VSL is warranted.

"Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is a Lower VRF because the tap setting data does not change frequently, and a violation is not expected adversely affect the BES.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement would not adversely impact the BES

	if violated. The tap information is provided during interconnection, and it is not expected to change frequently. Therefore, a Lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The parts within Requirement R5 are consistent with Requirement R5 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: There are no other standards that address Tap settings.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation is similar to an administrative violation. Further, since tap settings are infrequently changed, a violation would not adversely impact the BES.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

the Current Level of Compliance	
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for “Binary” Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation,	The proposed VSL is not based on cumulative number of violations.

Not on A Cumulative Number of Violations	

VRF Justification – VAR-002-3 Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is a Lower VRF because the tap setting data does not change frequently, and a violation is not expected adversely affect the BES.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement would not adversely impact the BES if violated. The tap information is provided during interconnection, and it is not expected to change frequently. If a violation were to occur, the system would still operate at the level prior to making any tap setting changes. Therefore, a Lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The part within Requirement R6 is consistent with Requirement R6 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: There are no other standards that address Tap settings.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation is similar to an administrative violation. Further, since tap settings are infrequently changed, a violation would not adversely impact the BES.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the requirement focuses on whether tap changes were made. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-002-3

Comment Period Open Now Open through April 14, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: April 4-14, 2014

Now Available

A comment period for **Project 2013-04 – Voltage and Reactive Control (VAR-002-3 - Generator Operation for Maintaining Network Voltage Schedules)** is open through **8 p.m. Eastern on Monday, April 14, 2014.**.

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

Instructions
Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
An additional ballot of **VAR-002-3** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 4, 2014 through 8 p.m. Eastern on Monday, April 14, 2014**.

For more information on the Standards Development Process, please refer to the Standard Processes Manual.

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-002-3

Comment Period Open Now Open through April 14, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: April 4-14, 2014

Now Available

A comment period for **Project 2013-04 – Voltage and Reactive Control (VAR-002-3 - Generator Operation for Maintaining Network Voltage Schedules)** is open through **8 p.m. Eastern on Monday, April 14, 2014.**.

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

Instructions
Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
An additional ballot of **VAR-002-3** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 4, 2014 through 8 p.m. Eastern on Monday, April 14, 2014**.

For more information on the Standards Development Process, please refer to the Standard Processes Manual.

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-002-3

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, April 16, 2014.**

This standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval	Non-Binding Poll Results
Quorum: 78.03% Approval: 82.40%	Quorum: 76.52% Supportive Opinions: 79.09%

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

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the standard does not show the need for significant revisions, it will proceed to a final ballot

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2013-04 Voltage and Reactive Control VAR-002-3
Ballot Period:	4/4/2014 - 4/16/2014
Ballot Type:	Additional
Total # Votes:	309
Total Ballot Pool:	396
Quorum:	**78.03 % The Quorum has been reached**
Weighted Segment Vote:	82.40 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	106	1	58	0.817	13	0.183	0	9	26
2 - Segment 2	9	0.5	5	0.5	0	0	0	1	3
3 - Segment 3	86	1	54	0.818	12	0.182	0	2	18
4 - Segment 4	30	1	16	0.667	8	0.333	0	2	4
5 - Segment 5	98	1	48	0.75	16	0.25	1	6	27
6 - Segment 6	52	1	37	0.804	9	0.196	0	2	4
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment	3	0.2	2	0.2	0	0	0	0	1

9									
10 - Segment 10	8	0.5	5	0.5	0	0	0	0	3
Totals	**396**	**6.5**	**228**	**5.356**	**58**	**1.144**	**1**	**22**	**87**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)

1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments will be submitted by Public Service Enterprise Group)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	

1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Association)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon / Exelon)

3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	Supports FirstEnergy's comments
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oglethorpe Power Corporation)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comments.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service

				Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	COMMENT RECEIVED
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of Indiana and Florida Municipal Power Agencies (IMPA & FMPA))
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen		
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon / Exelon)
4	Consumers Energy Company	Tracy Goble		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oglethorpe Power Corporation)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	

4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kedrowski for We Energies)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (prior comments by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	NO COMMENT RECEIVED - (Jerry Farringer)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris

				Scanlon / Exelon)
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lafayette Utilities System	Jamie B Webb	Abstain	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Bonnie Marino-Blair		
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments will be submitted by Public Service Enterprise Group)
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County,	Michiko Sell	Affirmative	

	Washington			
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Vandolah Power Company L.L.C.	Douglas A. Jensen		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon / Exelon)
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	

6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-Binding Poll Results

Project 2013-04 Voltage and Reactive Control (VAR)
VAR-002-3

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2013-04 Voltage and Reactive Control VAR-002-3
Poll Period:	4/4/2014 - 4/16/2014
Total # Opinions:	277
Total Ballot Pool:	362
Ballot Results:	76.52% of those who registered to participate provided an opinion or abstention; 79.09% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	

1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Abstain	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))

1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	

1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota		
2	California ISO	Rich Vine		
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Abstain	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oglethorpe Power Corporation)
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	

3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Nebraska Public Power District comment.)
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith		
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support comments of Indiana & Florida Municipal Power Agencies

				(IMPA & FMPA))
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Clewiston	Kevin McCarthy	Negative	SUPPORTS THIRD PARTY COMMENTS - (fmpa)
4	City Utilities of Springfield, Missouri	John Allen		
4	Consumers Energy Company	Tracy Goble		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oglethorpe Power Corporation)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Frank Gaffney, FMPA)
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kedrowski for we energies)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Prior comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly		
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Abstain	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	

5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas		
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Bonnie Marino-Blair		
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	

5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer		
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Abstain	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Affirmative	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Keith Morisette)
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito		
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2013-04 Voltage & Reactive Control

The Voltage & Reactive Control Drafting Team thanks all commenters who submitted comments on the draft VAR-002-3. These standards were posted for a 45-day public comment period from February 27, 2014 through April 14, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 112 different people from approximately 68 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

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

10. Mark Kenny	Northeast Utilities	NPCC	1
11. Christina Koncz	PSEG Power LLC	NPCC	5
12. Helen Lainis	Independent Electricity System Operator	NPCC	2
13. Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14. Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
15. Bruce Metruck	New York Power Authority	NPCC	6
16. Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18. Robert Pellegrini	The United Illuminating Company	NPCC	1
19. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21. Brian Robinson	Utility Services	NPCC	8
22. Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
23. Brian Shanahan	National Grid	NPCC	1
24. Wayne Sipperly	New York Power Authority	NPCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Erika Doot	US Bureau of Reclamation	X				X					

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

No Additional Responses

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

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Louis Slade	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton	NERC Compliance Policy	NA - Not Applicable	1, 3, 5, 6
2. Randi Heise	NERC Compliance Policy	NA - Not Applicable	1, 3, 5, 6
3. Connie Lowe	NERC Compliance Policy	NA - Not Applicable	1, 3, 5, 6
4. Chip Humphrey	Power Generation Compliance	NA - Not Applicable	5
5. Nancy Ashberry	Power Generation Compliance	RFC	5

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

6.	Dan Goyne	Power Generation Compliance	NA - Not Applicable	5
7.	Jarad L Morton	Power Generation Compliance	NPCC	5
8.	Larry Whanger	Power Generation Compliance	SERC	5
9.	Larry Nash	Transmission Compliance	SERC	1, 3
10.	Angela Park	Electric Transmission Compliance	SERC	1, 3
11.	Candace L Marshall	Transmission Compliance	SERC	1, 3
12.	Larry W Bateman	Electric Transmission Compliance	SERC	1, 3
13.	John Calder	Electric Transmission Compliance	SERC	1, 3
14.	Jeffrey N Bailey	Nuclear Compliance	SERC	5
15.	Tom Huber	Nuclear Compliance	NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Derrick Davis	Texas Reliability Entity, Inc.										X
No Additional Responses													
7.	Group	Marcus Pelt	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company generation; Southern Company Generationa and Energy Marketing	X		X		X	X				
No Additional Responses													
8.	Group	Shannon V. Mickens	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Louis Guidry	Cleco Power	SPP	1, 3, 5
3.	Michael Jacobs	Camstex	NA - Not Applicable	NA
4.	Mike Kidwell	Empire District Electric Company	SPP	1, 3, 5
5.	Nick McCarty	Kansas City Power and Light	SPP	1, 3, 5, 6
6.	James Nail	City of Independence Missouri	SPP	3
7.	Steve Ricard	Sunflower Electric Power Corporation	SPP	1
8.	Stephanie Johnson	Westar	SPP	1, 3, 5, 6
9.	Mahmood Safi	Nebraska Public Power District	SPP	1, 3, 5

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

10. J.Scott Williams	City Utilities of Springfield	SPP	1, 4
11. Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Matt Schebler	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Watson	Dynegy	SERC	5
2.	Ray Phillips	AMEA	SERC	4
3.	Tim Hattaway	PowerSouth	SERC	1, 5
4.	Richard Jackson	Alcoa Power Generating	SERC	5, 6, 7
5.	Scott Brame	NCEMC	SERC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities	RFC	1
2.	Brent Ingebrigtson	LG&E and KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Service	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1

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

8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3

				1	2	3	4	5	6	7	8	9	10
12.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Paul Jackson	Buckeye Power, Inc.	RFC	3, 4
4.	Amber Skillern	East Kentucky Power Cooperative	SERC	1, 3, 5
5.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
7.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
8.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
9.	Steve Ricard	Sunflower Electric Power Corporation	SPP	1
10.	Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 5

				1	2	3	4	5	6	7	8	9	10
13.	Group	Mike O'Neil	Florida Power & Light	X									

No Additional Responses

				1	2	3	4	5	6	7	8	9	10
14.	Group	Richard Hoag	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Larry Raczkowski	FirstEnergy Corp	RFC	3
3.	Doug Hohlbaugh	Ohio	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Query	FirstEnergy Solutions	RFC	6
6.	Richard Hoag	FirstEnergy Corp		NA

				1	2	3	4	5	6	7	8	9	10
15.	Individual	John Falsey	Invenergy LLC					X					
16.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
17.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
18.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
20.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
21.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
22.	Individual	Barbara Kedrowski	Wisconsin Electric Power Co			X	X	X					
23.	Individual	Bill Fowler	City of Tallahassee			X							
24.	Individual	Bernard Johnson	Oglethorpe Power Corporation					X	X				
25.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
26.	Individual	Karen Webb	City of Tallahassee					X					
27.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
28.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				

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

Organization	Agree	Supporting Comments of “Entity Name”
Invenergy LLC	Agree	PSEG Public Service Enterprise Group
Occidental Chemical Corporation	Agree	Ingleside Cogeneration, LP
Oglethorpe Power Corporation	Agree	ACES
South Carolina Electric and Gas	Agree	SERC OC

1. Please provide your comments on the proposed VAR-002-3 below:

Organization	Question 1 Comment
Northeast Power Coordinating Council	Section M1. Add the word "in" to the following sentence: "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 difference control mode ...."Footnote 3: suggest rewording the sentence to "The generator voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or a Reactive Power range communicated by the Transmission Operator to the Generator Operator."Footnote 4: suggest rewording the sentence to "A generating Facility's capability may be established by tests or other means, and may not be sufficient at times to return the system voltage within the schedule tolerance band...."Section M2, part 2.3: suggest rewording the sentence to "Generator Operators that do not monitor the voltage at the location specified on the voltage schedule shall document or be able to demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator."R3: While we agree with the 30 minute window to allow a GOP time to resolve an issue before having to notify the TOP of a status or capability change, the second part of the sentence seems to negate the first. The GOP has to notify the TOP of a status change within 30 minutes but if the status has been restored within 30 minutes then the GOP is not required to notify the TOP of the status change.Rationale for R4: typo in the version number of the standard VAR-002-2b.Section R4: remove the word "then" and "to" in the sentence. Suggest rewording the sentence to "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 the first 30 minutes of such change, the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability".R1 Severe VSL: for consistency with the wording of the requirement, suggest rewording to "Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage

Organization	Question 1 Comment
	control mode ...."R2 Severe VSL: for consistency with the wording of the requirement, suggest adding the word "the" to the sentence: "The Generator Operator did not maintain the voltage or Reactive Power schedule ...." And "The Generator Operator did not modify the voltage when directed ....".R5 High VSL and Severe VSL: the requirement on page 9 applies to the Generator Owner yet the responsible entity for the VSL is the Generator Operator. The word " Generator Operator" needs to be changed to "Generator Owner".
Response: Thank you for your comments. Several of the clarifying changes were made to the wording in the standard based on your feedback. VSLs for R5 and rationales were also corrected. However, the intent behind R3 was to allow GOPs 30 minutes to address or correct an issue before having to notify the TOP of the status change. Currently, if the AVR goes in and out of service multiple times within a short timeframe, the GOP is obligated to make multiple notifications to the TOP, even if the AVR is corrected in less than a few minutes. The drafting team concluded the other suggested changes did not provide additional clarify.	
US Bureau of Reclamation	The US Bureau of Reclamation (Reclamation) reiterates that the VSLs for VARâ€002â€3 R3 and R4 should reflect a range of noncompliance like in VARâ€002â€2. A failure to notify the Transmission Operator of an AVR, power system stabilizer, or reactive capability change for 35 minutes should not be treated as severely as a failure to notify the Transmission Operator of a status change for 75 minutes or longer. Reclamation recommends that R4 be updated to specify a threshold of reactive capability change that requires notification (e.g., 20 MVAR). As written, R4 would require GOPs to notify TOPs of a change in reactive capability of as little as 1 MVAR. Reclamation also requests clarification on types of “changes in reactive capability” that could trigger the notification requirement in R4.Reclamation suggests that the time horizon for R6 should be changed from “Realâ€Time Operations” to “Operations Planning” to match VARâ€001â€4 R6 and reflect that tap setting changes are agreed upon in advance rather than in realâ€time. If the drafting team intends only to refer to tap settings that can be adjusted in real-time (e.g., On Load Tap Changers), the requirement should be more specific.Reclamation appreciates the drafting team’s efforts and recognizes that the proposed revisions include a number of improvements to VAR-001 and VAR-002. However, Reclamation disagrees with the drafting team’s approach to responding to all

Organization	Question 1 Comment
	November 2013 comments on VAR-002 with the statement, "Thank you for your comments. VAR-002 did not pass the last ballot, and the VAR SDT will consider this during the next successive ballot." By responding in this way to all VAR-002 comments, the drafting team provided no responses to the technical issues raised by commenters.
Response: Thank you for your response. The drafting team determined that the best way to ensure reliability was to allow the TOP to provide guidance on when to make notifications based on system needs. This is reflected in VAR-001-4 where the TOP may exempt GOPs from making certain notifications. Further, the drafting team determined that it was not possible to set a reactive capability change threshold that could apply continent-wide. Such a threshold will have to vary based on the entity's size and location of the entity. The drafting team did not change the time horizon for R6 because the currently enforceable standard that previously passed industry comment and ballot used "Real-time operations."	
Arizona Public Service Company	R3 & R4: Please provide the technical justification for the 30 minute time limit. Also, please provide an example of a specific action taken by the Transmission Operator in response to a notification of status change of AVR or PSS. In order to allow the GO time to fix minor problems before reporting, a minimum of 60 minutes should be allowed. This will eliminate unnecessary reporting and limit the impact of reporting on the Transmission Operator. We recommend that all time periods in these requirements be changed to 60 minutes.R5.1: copied below for discussion:For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage: The above language implies that if my GSU primary voltage is rated less than the generator primary voltage, this requirement will not apply. Hopefully, that is not the intent. There are examples of GSU transformers that have the primary voltage intentionally specified to be 5% less than the generator rated voltage to provide a voltage boost. R6: This requirement implies that an action is required whether there is a need for tap change or not. It should be clarified that it applies only when either a GO or a TO is planning a tap change.

Organization	Question 1 Comment
Response: Thank you for your comments. The 30 minutes was selected for two reasons: 1) an IROL T_v must be corrected within 30 minutes in accordance with the NERC Glossary, and 2) the industry consensus was that 30 minutes was appropriate for R3 and R4.	
DTE Electric	Positive improvements!Two minor grammar changes:Second sentence of R3 and R4 - remove "to" before "the Generator Operator"If the capability has been restored within 30 minutes of such change, then to the Generator Operator...
Response: Thank you for your comments. The word "to" was removed from the requirements R3 and R4.	
Dominion	Dominion has the following comments. o While we do not strongly oppose inclusion of the last sentence in requirements 3 and 4, we do not believe they are necessary. We are slightly concerned that such inclusion in this standard could infer that notification is required under similar circumstances in other standards o If the SDT choses to keep the last sentence in R3 and R4, Dominion suggests removing the first 'to' to read "....then the Generator Operator is not required to....".
Response: Thank you for your comments. The last sentences in R3 and R4 are necessary to avoid the situations where multiple entities are notifying TOPs of an issue being addressed/corrected thereby diverting the TOP from their primary objective of system reliability. The drafting team also removed the word "to" from both requirements R3 and R4.	
Texas Reliability Entity, Inc.	We would suggest rewording R2.2 to say "When instructed to modify voltage, the Generator Operator shall comply unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. If the Generator Operator cannot comply with the Transmission Operator's instructions, the Generator Operator shall provide an explanation why the instruction cannot be met."In R4, does the "reactive capability" include static capacitive or reactive devices that are behind the fence (for example, static capacitors and reactors installed on the low voltage feeders at wind plants). Would this requirement apply to such devices if they are not included in the Bulk Electric System per the new BES definition?The status and capability notifications in R3 and R4 may be directly or indirectly in conflict with IRO-005-3.1a, R1.1, TOP-005-2a,

Organization	Question 1 Comment
	Attachment 1, Item 1.2.4, and TOP-006-2, R2. These requirements require monitoring the status of generation and/or AVR status by the RC and BA, as well as the TOP. Will the TOP and RC be able to satisfy their obligations under these other standards in view of the proposed GOP reporting parameters?
Response: Thank you for your comments. The drafting team did not adopt the suggested changes in Part 2.2 because it is outside the scope of what was being addressed in this project. With regard to R4, the TOP may provide the GOP with an exemption for certain notifications under VAR-001-4, and the BES definition will apply with regard to the applicability of this standard.	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company generation; Southern Company Generationa and Energy Marketing	Southern Company has the following general comments that are meant to provide non-substantial changes to parts of the standard:1. In the second sentence of the "Rational for R3" box, add "of this type of status change" between "notifications" and "provide". This provides emphasis that the scenario described in the first sentence is one type of status change that may occur. 2. In the third sentence of the "Rational for R3" box, delete "or capability". R3 deals with status changes and R4 deals with capability changes.3. In R4, delete the unneeded word "to" in the second sentence that appears between "then" and "the": ",,, change, then to the Generator Operator is not required ...."4. It is noted that TOP-003-2, R5 and MOD-032-1, R2 (both currently filed with FERC for approval) contain requirements for the GO to provide data to the TOP and the TP similar to that found in VAR-002-3 R5. Duplication of identical requirements for the GO may occur if all three standards are ratified.
Response: Thank you for your comments. The drafting team adopted most of the changes based on your feedback. However, the drafting team retained R5 because the TOP standards are currently being revised. Additionally, MOD-032-1, which is currently pending before FERC, addresses a different time horizon.	
SPP Standards Review Group	Standard:In Requirement R3 second sentence, we would suggest the removal of 'to' from the phrase ' then to the Generator' and have it to read as followed: 'then the Generator Operator'. In Requirement R 4 we would like to suggest the second sentence to be revised and to read as followed; "If the capability has been restored within 30 minutes of

Organization	Question 1 Comment
	becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. In Requirement R4 second sentence, we would suggest the removal of ‘to’ from the phrase ‘ then to the Generator’ and have it to read as followed: ‘then the Generator Operator’. In the last line of the 2nd bullet of R1, insert space between ‘Operator’ and ‘for’.Capitalize Part whenever it is referencing a Requirement. For example, in the Rationale Box for R2, the last sentence in the 1st paragraph would read ‘Additionally, a new Part 2.3 has been...’ Do this throughout the standard.In the Rationale Box for R4, correct the reference to VAR-002-2b.In the Rationale Box for R5, the 3rd sentence should read ‘The prior version of VAR-002-2b, Part 4.1.4 (the +/- voltage range...’In the High VSL for R2, insert an ‘a’ between ‘have’ and ‘conversion’.Replace ‘cannot’ with ‘could not’ in the Severe VSL for R6.RSAWIn the RSAW R5 (page 11) under Evidence Requested11, we would like to suggest changing ‘M4’ to ‘M5’....then it would read ‘Evidence as outlined in M5’.Similar to the standard, Part should be capitalized when referenced in conjunction with a requirement.In the 3rd row of the table under the Compliance Assessment Approach Specific to VAR-002-3, R2 heading, delete the ‘in’ in the last line in the cell. In the 5th line in the 1st paragraph in the Note to Auditor section, insert a comma between ‘sound’ and ‘only’ such that it reads ‘...documentation review, are sound, only limited audit...’. In the last line of the same paragraph, insert a ‘the’ between ‘that’ and ‘entity’.In the 3rd row of the table under the Compliance Assessment Approach Specific to VAR-002-3, R3 heading, insert a ‘the’ between ‘if’ and ‘entity’. In the 5th line in the 1st paragraph in the Note to Auditor section, insert a comma between ‘sound’ and ‘only’ such that it reads ‘...documentation review, are sound, only limited audit...’. In the last line of the same paragraph, insert a ‘the’ between ‘that’ and ‘entity’.In the Evidence Requested table for R4, insert a ‘the’ in front of ‘entity’ or ‘entity’s’ in the 2nd and 3rd line of the 2nd row and the 1st line of the 3rd row. In the 1st line of the 3rd row of the table under the Compliance Assessment Approach Specific to VAR-002-3, R4 heading, insert a ‘the’ between ‘if’ and ‘entity’.In the Evidence Requested table for R5, change the reference to M5 in the 2nd row to M4.In the 1st line of the 2nd row of the table under the Compliance Assessment Approach Specific to VAR-002-3, R5 heading, insert a ‘the’ between ‘if’ and ‘entity’.In the 1st line of the 2nd

Organization	Question 1 Comment
	row of the table under the Compliance Assessment Approach Specific to VAR-002-3, R6 heading, insert a 'the' between 'if' and 'entity'.
Response: Thank you for your comments. The drafting team was able make most of the recommended changes to the standard. The drafting team will forward your recommendations for the RSAW to NERC Compliance staff for their consideration.	
SERC OC Review Group	Requirement R1:The OC Review Group believes that R1 would be strengthened with further report timing clarification is required in the case where the AVR changes state unexpectedly. The OC Review Group respectfully recommends adding a bullet to R1 which reads "In cases where the AVR changes state unexpectedly the Generator Operator will notify the Transmission Operator within 30 minutes."Current 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] o 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 o That the generator is not being operated in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing. Proposed 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] o 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 o That the generator is not

Organization	Question 1 Comment
	being operated in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing. o In cases where the AVR changes state unexpectedly the Generator Operator will notify the Transmission Operator within 30 minutes only if reactive capability is not restored.Measure 1:The OC Review Group recommends that Measure 1 be modified to specifically include that SCADA alarming may be used for real-time notification.Current Measure 1: 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 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). Proposed Measure 1: 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 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. SCADA alarming may be used for real-time notification. 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). Requirement 2:The OC Review

Organization	Question 1 Comment
	Group believes and recommends that the phrase “or other control capabilities” to provide further clarification to the Requirement.Current R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedulecapabilities4) 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] Proposed R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage, Reactive Power schedule, or other control capabilities 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] Measure 2:The OC Review Group believes and recommends that the phrase “or other control capabilities” to provide further clarification to the Measure.Current M2, paragraph 1: 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. Proposed M2, paragraph 1: 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, Reactive Power schedule or other control capabilities, 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

Organization	Question 1 Comment
	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.Requirement 3:The OC Review Group believes that R3 would be strengthened with further report timing The OC Review Group respectfully recommends adding a bullet to R3 which reads “The Generator Operator is not required to notify the Transmission Operator of the status change if the change is expected as part of a startup, shutdown, or testing procedure previously provided to the Transmission Operator per Requirement 1.”Current 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 to the Generator Operator is not required to notify the Transmission Operator of the status change [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]Proposed 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 to the Generator Operator is not required to notify the Transmission Operator of the status change [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] o The Generator Operator is not required to notify the Transmission Operator of the status change if the change is expected as part of a startup, shutdown, or testing procedure previously provided to the Transmission Operator per Requirement 1.Measure 3:The OC Review Group recommends that Measure 3 be modified to specifically include that SCADA alarming may be used for real-time notification.Current Measure 3: 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. Proposed Measure 3: The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. SCADA alarming may be used for real-time notification. If the status has been restored within the first 30 minutes, no notification is

Organization	Question 1 Comment
	necessary. Requirement 4:Current 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 such change, then to 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] The SERC OC Review Group respectfully requests further clarification for the phrase “becoming aware of a change in reactive capability”. Without clarifying the size “of a change in reactive capability” it is possible that the TOP will receive numerous calls reporting extremely small changes in reactive capability.Violation Severity Levels:Requirement 1: The SERC OC Review Group proposed change does not require VSL modifications.Requirement 2: The SERC OC Review Group proposes the following change to the VSL to reflect the modification to Requirement 2. Current R2 Severe VSL: The Generator Operator did not maintain voltage or Reactive Power schedule as directed 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. Proposed R2 Severe VSL: The Generator Operator did not maintain voltage, Reactive Power schedule, or other control capabilities as directed 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. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.

Response: Thank you for your comments. The drafting team did not make the suggested change to R1 because it would create a conflict with R3. The measure for R3 does not prevent SCADA alarms/data from serving as evidence of compliance, and the

Organization	Question 1 Comment
standard does not explicitly list all the forms of compliance. With regard to R4, the TOP can provide notification exemptions under VAR-001-4. This will allow the TOP to tailor notifications based on size of reactive capability if necessary. For the R2 VSL, the language was not modified because the GOP must maintain the voltage or Reactive Power schedules, regardless of the method of control.	
PPL Corporation NERC Registered Affiliates	1. The PPL NERC Registered Affiliates agree with R2 stating that GOPs shall maintain the voltage/MVAR schedule or meet the TOP's deviation notification criteria; however, there is no explicit requirement for TOPs to issue any such notification criteria. We request that the standard be revised to require TOPs to issue reasonable notification criteria for deviations from the TOP-provided voltage or reactive power schedule. Such criteria can enhance reliability by reducing the number of repetitive, unnecessary telephone calls to TOP system operators that could distract from other reliability tasks. 2.We recommend that the first sentence of VAR-002-3 R6 be changed from, "After consultation with the Transmission Operator regarding necessary step-up transformer tap changes," to, "After consultation with the Transmission Operator regarding necessary step-up transformer tap changes and the implementation schedule," to mirror the language in R6 of VAR-001-3.3. We wish to point-out also that the low side-to-high side ratio of a transformer is fixed only for an ideal (no losses) device, and for actual equipment it changes with load (termed "regulation"), and this effect is not trivial in magnitude. The "Rationale for R2" section of VAR-002-3 explicitly permits "straight ratio conversion," however; so, if the standard passes in its present form, GOPs using this method can be officially compliant yet factually operating well outside the voltage schedule bandwidth. The term, "straight ratio conversion," should be replaced with "nominal ratio conversion compensated for transformer regulation."3. We recommend that Measures M1 and M3 include language that would allow for SCADA alarms to count as evidence of notification to the TOP from the GOP. We suggest adding the language, "SCADA alarming, or some other electronic automatic system, may be used for real-time notification."
Response: Thank you for your comments. VAR-001-4 does address TOP notification requirements, and VAR-001-4 allows the TOP to tailor the notifications based on their system needs. For R6, the consultation with the TOP can encompass the implementation schedule. R2 rationale was not modified because the standard allows each entity to select the conversion	

Organization	Question 1 Comment
methodology that best suits their needs. For M1 and M3, SCADA alarms are not precluded as evidence of compliance, but the drafting team did not want to provide an exhaustive list of all forms of compliance.	
Florida Municipal Power Agency	There are grammar issues with R1 including a ambiguous references. There are at least two ways to read R1: (i) does R1 mean that the AVR is put into automatic voltage control mode as a default with the ability to operate in a different control modes only at the instruction of a TOP - in other words, there is no instruction from a TOP if the AVR is operating in automatic voltage control mode; or (ii) a TOP instruction is required to determine in which control mode to operate, including automatic voltage control mode? Also, does the "... unless ..." and the ensuing two bullets apply only to alternative control modes or also to automatic voltage control mode?Another ambiguity is the use of the word "notified" in R1. "Notify" as used in R3 allows the GOP a 30 minute (after the fact) window. Does R1 allow the same after the fact notification period? R1, R2, R3 and R4 all include notifaction provisions that in some ways overlap and cause confusion. If the Generator Operator needs to take immediate or emergency actions and transfer the automatic voltage controller from "auto" to "manual", it is not clear in the requirements (especially requirement R1) that the Generator Operator is allowed to perform this action without obtaining prior instruction from the Transmisison Operator or giving prior notification to the Transmission Operator. FMPA believes it would be clearer to re-write R1, R2, R3 and R4 into two requirements: R1 for desired performance and R2 for notifications of when that performance cannot be maintained.FMPA offers the following re-write of R1, R2, R3 and R4 into two proposed requirements that we believe reflects the intent of the SDT while clarifying:"R1 The Generator Operator shall operate each generator connected to the interconnected transmission system with its automatic voltage regulator (AVR): (i) in service; (ii) in the control mode instructed by the Transmission Operator; and (iii) maintaining the generator voltage or Reactive Power schedule (within each generating Facility's capabilities) provided by the Transmission Operator, unless: (a) the generator is exempted by the Transmission Operator; (b) the generator does not have an AVR; or (c) the Generator Operator has notified the Transmission Operator in accordance with R2 of an inability to meet these performance requirements:1.1 When a generator's AVR is out of service or the generator does not have

Organization	Question 1 Comment
	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.1.2 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.R2 Each Generator Operator shall notify its associated Transmission Operator prior to or within 30 minutes of becoming aware of any of the following, unless the performance requirements of R1 are restored within 30 minutes: o That the generator is not being operated in the control mode that was instructed by the Transmission Operator; or o A status change of the AVR, power system stabilizer, or alternative voltage controlling device o A change in reactive capability of a generator due to factors other than those described aboveA procedure previously provided by the Generator Operator to the Transmission Operator that includes a description of AVR, power system stabilizer or alterantive voltage controlling device status changes or control mode changes during start-up, shutdown or testing acts as standing notification such that the Real-time communication of start-up, shutdown, or testing also fulfilles the required notification."FMPA is aware that this offered language removes the SDTs proposed R2 bullet 2.2 that requires the GOP to modify voltage when instructred to do so by the TOP; however, this bullet is duplicative of the parent requirement (e.g., if a TOP instructs the GOP to modify voltage, is that not a new voltage schedule, albeit maybe a temporary schedule?) and TOP-001-1, R3 that requires GOPs to comply with directives from a TOP. FMPA believes that this offered alterantive language simplifies and clarifies the SDT's intent.

Response: Thank you for your comments. R1 has been modified to provide clarity with regard to AVR settings. R1 clearly states that the AVR must be run in either controlling voltage mode or the mode instructed by the TOP. The only time that the GOP can run in a different mode or in manual is if the GOP has been exempted or the GOP has notified the TOP of one of the bulleted items. Both bullets for R1 still apply to the entire body of R1. Further, the timing for the second bullet of R1 must work in tandem with the new R3.

Organization	Question 1 Comment
ACES Standards Collaborators	(1) VAR-002-3 R1 is confusing. Please clarify the second bullet in R1 so it ties into the previous part of the sentence. Read literally, R1 states, “The GOP 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 TOP unless... 2) the GOP has notified the TOP of one of the following: [second bullet] That the generator is not being operated in the control mode that was instructed by the TOP for a reason other than start-up, shutdown, or testing.” This exception is circular and needs to be revised.(2) The RSAW for R1 does not provide any additional details for compliance beyond the language in the requirement and corresponding measure. We would like to see additional compliance statements in the RSAWs, especially considering that the compliance input document contained several relevant issues with VAR-002-3.(3) VAR-002-3 R2 and Part 2.1 need to be modified so that the GOP is only required to follow the voltage schedule if provided by the TOP. It is not desirable for the TOP to provide all generators voltage schedules. As an example, the TOP may determine it does not need to provide a voltage schedule to a small generator. To consider this situation, the clause “if a voltage schedule is provided by the TOP” could be added to both Part 2.1 and the main requirement. (4) VAR-002-3 R2 will be problematic for some GOPs because it does not reflect the characteristics of the voltage schedule provided by some TOPs. For example, some TOPs provide an hourly average voltage schedule to avoid the need for notification for every time the GOP drifts out of schedule. How would R2 be applicable in this situation? Would it only apply for the first 15 minutes of each hour looking back at the last hour? Please modify the requirement accordingly to address this issue.(5) The RSAW for R2 contains ambiguous language, stating that the auditor should “select a sample of timeframes” to verify compliance. The evidence retention section (section C.1.2.) of VAR-002-3 states that the Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers and maintain all other evidence for the current and previous calendar year. The RSAW should be revised to “review instances when a generator deviates from its schedule” for time periods applicable to the evidence retention section of the standard. (6) VAR-002-3 R3 is improved by expanding the time from 15 to 30 minutes before a GOP must notify the

Organization	Question 1 Comment
	TOP of a status or capability change. We thank the drafting team for providing additional flexibility.(7) The RSAW for R3 states that the auditor may select certain instances where an entity had a status change on AVR. Is the intent of the drafting team to require an entity to maintain a list of all status changes? This does not appear to align with the requirement, especially considering that the rationale for R3 clarifies that the requirement was modified to limit notifications for quick status changes, as these provide little to no benefit to reliability. Having to maintain a list of status changes for an auditor verify also provides little to no benefit to reliability. We recommend revising the RSAW to state that the auditor may select "evidence of GOP status change notifications to its TOP."(8) Requirement R4 in the RSAW is inconsistent with the requirement in the proposed standards. It still contains 15 minutes which has been updated to 30 minutes in the latest proposed standard.(9) VAR-002-3 R4 could be clarified further in the second sentence to account for awareness. We recommend modifying the language to state, "If the capability has been restored within 30 minutes of [becoming aware] of such change..." This revision will align both sentences in R4.(10) We are concerned about the statement in the "Note to Auditor" section that the auditor will look for instances "where it is likely that an entity was made aware of the change in reactive capability" such as when a unit trips or an AVR fails. The statement is problematic for two reasons. First, the requirement is clear that the GOP must be aware of the change before they are required to communicate it. The auditor should not be looking for evidence such as when an AVR fails but rather for log book entries and similar information that the GOP was aware of the change. They should not be looking for when the AVR went offline. Second, a unit trip is a bad example because the TOP will have telemetry necessary to observe when a unit is forced off-line. Is it really necessary to have a compliance requirement for the GOP to notify the TOP when the TOP will already know of the unit's off-line status? We agree that communication between the GOP and the TOP should take place following such an event, but we do not think it rises to a compliance level for this specific example.(11) VAR-002-3 R5 meets multiple P81 criteria and should be removed. It meets Criterion A because it does little, if anything, to benefit or protect the reliable operation of the BES. It also meets Criterion B2 - Data Collection/Data Retention and Criterion B4 - Reporting because

Organization	Question 1 Comment
	it requires the GOP to gather their tap setting information and report it to a third party (i.e. its TOP), which is unnecessary to implement, as a reliability requirement. A GOP is not going to refuse to provide data to its TOP on its generator step-up transformer in a compliance-driven world. In fact, making this data subject to compliance slows down the free exchange of the information because of all the extra checking that goes into managing (i.e. verifying, checking, storing) compliance documentation. This requirement also meets B7 - Redundant because the TOP can specify this data in its data specification per TOP-003-2 R1, distribute it to the GO per TOP-003-2 R3, and then have the GO respond per TOP-003-2 R5. We do not support the VSLs for R5 because it meets P81 criteria and should be removed. (12) The RSAW for R5 should specify the evidence auditors will verify, including tap settings, available fixed tap ranges, and impedance data. The current RSAW refers to “evidence as outlined in M4.” This is an incorrect reference to the wrong measure and needs to be updated.(13) VAR-002-3 Part 6.1 meets a P81 criterion and should be removed. It meets Criterion A because it does little, if anything, to benefit or protect the reliable operation of the BES. It also meets Criterion B4 - Reporting because it requires the GO to report a technical justification for not implementing tap changes. This technical justification simply does not support reliability. The TOP can make adjustments to other voltage schedules to account for the GO’s inability to implement the tap changes. What is the purpose of the GO providing the TOP a technical justification? Is it to provide the TOP some assurance there is a technical reason for failing to implement the tap changes? In a compliance-driven world, the TOP can reasonably expect the GOP to implement the tap changes unless the changes would violate safety, equipment limits, or regulatory and statutory requirements since these are the only deviations allowed by the main requirement. The threat of sanctions assures this. Furthermore, the GOP may legitimately not have a “technical” justification because a regulatory requirement is a legal justification, not a technical justification. (14) The RSAW for R6 needs to be developed. It is currently incomplete and does not list any evidence or any additional guidance beyond what is listed in the measure.(15) Thank you for the opportunity to comment.

Response: Thank you for your comments. R1 has been modified to provide clarity with regard to AVR settings. R1 clearly states that the AVR must be run in either controlling voltage mode or the mode instructed by the TOP. The only time that the

Organization	Question 1 Comment
GOP can run in a different mode or in manual is if the GOP has been exempted or the GOP has notified the TOP of one of the bulleted items. Both bullets for R1 still apply to the entire body of R1. The RSAW was concurrently developed with the standard so the intent of the drafting team is reflected in how compliance is assessed, but the RSAW is a NERC Compliance document that the drafting team does edits. However, these comments will be forwarded to the appropriate individuals for review. The drafting team could not remove the requirements to make tap setting changes and provide tap data under P81 because the TOP standards are being currently revised, and FERC has not approved the most recent MOD filing. Further, the data requirements are important for TOP studies which impact tap setting/max VAR output. With regard to the technical justification for a tap setting, the TOP will need to understand why the GOP cannot make a tap setting modification. Changing a tap will impact reactive support from a generating unit, and this will impact reliability. Finally, the requirement to provide a technical justification is an existing requirement in the currently enforceable VAR-002-2b.	
Florida Power & Light	For R4, the loss of an individual wind turbine should not be considered a reactive capability change, since the real power capability would change incrementally along with the reactive capability change and in most cases other turbines would compensate for the reactive capability loss. In general, these requirements should all be applied on the aggregate level for dispersed generating resource facilities. Clarification on R5 is needed to better understand applicability of tap settings changes and request on dispersed generating resources as these typically are designed with a smaller padmount transformer or similar for each individual generating resource, along with a larger aggregating GSU to collect the aggregate generation. Intent would be to include the GSU, but exclude the smaller individual padmount transformers.
Response: Thank you for your comments. With regard to R4, the TOP may provide the GOP with an exemption for certain notifications under VAR-001-4, and the BES definition will apply with regard to the applicability of this standard.	
FirstEnergy Corp	FirstEnergy would like to offer the following comments:1. With regards to clarifying that the Generation Operator will follow the condition of notification of the Transmission Operator. We offered the following two options, where option 1 modifies the current red line version of the Requirement 2 and option 2 adds a sub Requirement to explicitly specify the situational required action of the Generator Operator for the Transmission Operator.OPTION 1:R2. Unless exempted by the Transmission Operator, each Generator

Organization	Question 1 Comment
	Operator shall maintain the generator voltage or Reactive Power schedule (within each generating Facility's capabilities) provided by the Transmission Operator, or otherwise shall meet the conditions of notification provided by the Transmission Operator for deviations from the voltage or Reactive Power schedule. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]OPTION 2:R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule3 (within each generating Facility's capabilities4) provided by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]2.1 The Generator Operator shall meet the conditions of notification provided by the Transmission Operator for deviations from the voltage or Reactive Power schedule. Then renumber remaining sub Requirement as needed.Pertaining to Measure 2:Remove the first sentence ("In order to identify when a unit generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility") from measure 2. This sentence does not apply to requirement 2 since it only requires the Generator Operator to maintain the generator voltage or Reactive Power schedule that is provided by the Transmission Operator. The inclusion of this sentence could be interpreted that the Generator Operator will need to provide evidence of "monitoring" activities which is not a performance based requirement.
Response: Thank you for your comments. The requirement and measure language was selected very carefully. The first and second sentences of M2 provide GOPs with the ability to monitor and maintain voltage based on existing equipment, and it does not require GOPs to install new metering.	
Manitoba Hydro	(1) R1 - R1 appears to be such a lax requirement that it is arguably unnecessary. Under the second bullet, the only step that a GO has to take in order to avoid compliance is to notify the TO that it is not complying and provide any reason whatsoever. This leads one to question how important the requirement is to reliability. (2) R3 - It appears that the two sentences in R3 conflict with each other. Based on the second sentence, the GOP is not required to notify the TOP if the status has been restored within 30 minutes. However, the first sentence requires the GOP to notify the TOP within 30 minutes of the change. If at the 30th minute, the GOP realizes that the status is not restored, there will not be enough

Organization	Question 1 Comment
	time for the GOP to notify the TOP. If the 30 minute notification time could be extended to 45 or 60 minutes, there will be enough time for the GOP to notify the TOP. (3) M3 - For consistency with that in R3, "the first" in the second sentence should be deleted. (4) R4 - Similar to that in R3, if the 30 minute notification time could be extended to 45 or 60 minutes, there will be enough time for the GOP to notify the TOP. (5) M4 - For consistency with that in R4, "the first" in the second sentence should be deleted. (6) Based on the Standards Process manual, "Time Horizon: The time period an entity has to mitigate an instance of violating the associated requirement." the Time Horizon for R5 and R6 should be changed from "Real-time Operations" to "Operations Planning" because in R5 the GO is required to provide the information within 30 days and in R6 the tap changes should be scheduled during an outage after consultation with the TOP.
Response: Thank you for your comments. R1 is important because it requires a notification to the TOP when the generator is not in AVR or the instructed control mode. It also provides flexibility for the GOP in case the AVR switches modes. The coordination is necessary in order to provide the TOP with the opportunity to plan for other reactive resources. The 30 minutes is similar to the requirement to correct T_V issues within 30 minutes. The 30 minutes did not exist in VAR-002-2b, and now the 30 minutes provide GOPs with the time to address issues before having to notify the TOPs. The time horizons for R5 and R6 exist in the currently enforceable standard, and were not modified by this drafting team.	
Exelon	1.VARâ€002â€3 Effective DatesThe Implementation Plan for VAR-001-4 and VARâ€002â€3 requires the new Standard revisions to be implemented the first day of the first calendar quarter after applicable regulatory approval, allowing for a situation in which the standard could receive regulatory approval towards the end of the calendar quarter, resulting in an effective date with little or no implementation time, e.g., if regulatory approval is received on March 30, the standard would need to be implemented on April 1. IN addition, although the Implementation Plan justification states that the VARâ€002 standard "cannot go into effect without the new TOP schedules and notification requirements" it does not address the implementation associated with changes to VARâ€002 with respect to status notifications. There is not sufficient time to allow generating units to implement training of operators and procedural changes necessary to implement the proposed changes to notification requirements associated

Organization	Question 1 Comment
	with the AVR, PSS or alternative voltage controlling device. In the VAR-002 Directives Project Implementation Plan, the NERC SDT acknowledges that the TOPs will "need some time" to adjust to providing data and therefore the TOPs are provided a quarter to prepare documentation. The GO/GOPs should be afforded at least that amount of time for implementation. We suggest a 6 month implementation period following regulatory approval.2.Dispersed GenerationThis version does not account for dispersed generation (such as wind or solar as found in the new BES definition). These generators may not have a traditional AVR, may only provide limited reactive resources and the individual elements may not have AVR or be capable of operating in voltage control mode. We understand Project 2014-04 is addressing standards changes for dispersed resources and recognize there are parallel efforts that may be difficult to reconcile. Given that, we request the Drafting Team consider how best to acknowledge that VAR-002-4 may have limited applicability to dispersed generation resources and that it is likely to be revised based on the work of Project 2014-04. 3.VAR-002-3 R2.3Exelon believes it is reasonable to allow the GOP to monitor the voltage specified in their TOP issued voltage schedule by allowing the GOP to monitor at a different location by applying a methodology for converting the voltage monitored; however, the conversion method should be specifically communicated to the TOP. There is not a one for one conversion between grid voltage and terminal voltage and therefore the conversion method and monitoring point should be clearly communicated to the TOP to avoid any future compliance audit or implementation issues.4.VSLsExelon understands that R3 and R4 are binary requirements as outlined in Guideline 2 of the "Violation Risk Factor and Violation Severity Level Justifications" associated with VAR-002-3, (e.g., did or did not notify in 30 minutes), it is however unreasonable that a complete failure to notify would have the same VSL as a notification that is one minute late versus one that is days or weeks late. We urge NERC to address this issue from reliability, not a strict compliance perspective; in instances such as this, there should be levels of severity not simply binary requirements.

Response: Thank you for your comments. The implementation schedule is shorter than other projects, but that date was selected originally because industry provided feedback that VAR-002-2b changes should be implemented quickly to avoid unnecessary notifications to the TOP. FERC has not historically approved standards within one quarter of filing. Further, the

Organization	Question 1 Comment
Dispersed Generation project has released its whitepaper, and no changes are being recommended for VAR-002-2b. The standard does not require the GOPs to provide TOPs with the methodology for conversion because the TOPs provided feedback that their primary concern was that the voltage schedule was maintained. The VSLs were simplified to remove the gradation in the currently enforceable requirement. If a large unit reports later than a small unit, then the severity will vary between the two. Therefore, the timing elements were removed since the requirements are binary in nature.	
American Electric Power	AEP would like to thank the drafting team for their efforts on this project. Their willingness to incorporate industry's input into the draft standard is very much appreciated.VSL Table: The High and Severe VSL entries for R5 should indicate Generator Owner rather than Generator Operator.
Response: Thank you for your comments. The VSL table has been updated.	
Public Service Enterprise Group	PSEG appreciates the SDT's hard work on this standard and we have only one comment.In R2, subpart 2.3 uses the words "monitor" and "monitored." These words have unintended implications in two respects:1. There was never an obligation in the prior version of VAR-002 that the GOP "monitor" its voltage. The objective in this standard, as in its predecessor, is to require the GOP to maintain a voltage or Reactive Power schedule specified by the TOP. (Under VAR-001-4, R5.3, a TOP's schedule must have tolerance bands, which is an improvement over the R4 in the current VAR-001-3.) While "monitoring" the TOP-specified schedule in an activity that may be related to maintaining such a schedule, is not the results-based purpose of the standard. 2. What would constitute acceptable monitoring? As written, this is an open question that an auditor must answer. It's possible that a GOP could be in violation of subpart 2.3 if its "monitoring" was deemed unacceptable by an auditor even though the GOP maintained the TOP's schedule within the tolerance bands 100% of the time!We therefore recommend that the SDT replace prescribed activities of "monitor" and "monitored," respectively in subpart 2.3, with the performance requirement of "maintain" and "maintained." This would preserve the requirement that the GOP have a conversion methodology if it does not maintain the voltage schedule at the location specified by in TOP's schedule, without also prescribing that GOPs monitor voltage to do so. To

Organization	Question 1 Comment
	implement this change, subpart 2.3 would read:"Generator Operators that do not maintain 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 maintained by the Generator Operator."
Response: Thank you for your comments. The intent behind Part 2.3 is to require a methodology for a conversion, and the drafting team chose the word "monitor" and "monitored" to specifically alleviate concerns that an auditor will take issue with monitoring equipment and where it is located. The drafting team used the word monitor to convey where the GOP has visibility of the voltage. The words "maintain" and "maintained" may introduce ambiguity in Part 2.3 because the industry was concerned that an auditor would question how voltage is maintained if the GOP and TOP are not metering the same point. The drafting team selected "monitor" and "monitoring" based on input from many GOPs that they did not want their monitoring systems questioned, nor did they want to be required to install new monitoring systems for this standard.	
Ingleside Cogeneration LP	Ingleside Cogeneration LP (ICLP) believes that VAR-002-3 Draft 3 adds much needed flexibility in the manner that GOP supports voltage at the transmission interconnection. Combined with the updates to VAR-001-4, we agree that close coordination with the TOP is inherent in the process - which is a key reliability need. A primary example is the allowance for the TOP to determine how the GOP may communicate changes in AVR and PSS status. Those of less intrinsic importance to BES reliability may be required to notify a status change through telemetry; high-impact generation facilities may need to call the TOP as well. The result is that distracting calls are eliminated - which can otherwise pose a threat to the BES in as of themselves.In fact, our only concerns are related to the draft RSAW that was posted concurrently with the standard. First, a further description in the RSAW under R1 and R2 which directs how the CEAs must react to a TOP voltage control strategy that goes against today's model. For example, if exemptions are given, it must be clear that it is not up to the auditor to question their technical veracity. Their only focus must be how well the Generator Operator adhered to the TOP's voltage/Reactive schedule. In addition, the auditor instructions for R2 needs to include a line item addressing footnote 4 which allows capability exceptions for adherence to the TOP's voltage/Reactive schedule. This may take two forms - first, if the external system attempts to force the generator past its Facility Rating limits. Such a condition may persist

Organization	Question 1 Comment
	indefinitely, and can damage the unit if compliance is forced. Second, a rapid change in loading will create Reactive-power spikes that can easily exceed the TOP's specified range. These typically last for under a minute and must also be accepted as compliant by the CEA. In both cases, a notification to the TOP is unnecessary as it will serve only as a nuisance call.
Response: Thank you for your comments. The RSAW was concurrently developed with the standard so the intent of the drafting team is reflected in how compliance is assessed, but the RSAW is a NERC Compliance document that the drafting team does not edit. However, these comments will be forwarded to the appropriate individuals for review.	
Wisconsin Electric Power Co	R1 As written, the requirement is difficult to interpret (four different actions or qualifictions for one requirement). The draft language allows the Transmission Operator to instruct the Generator Operator to operate a generator in any number of undefined control modes without prior agreements in place between the TO and GO. Prior versions of the draft standard allowed for unusual circumstances to be addressed via the, "unless the Generator Operator is exempted by the Transmission Operator" language. The rational for keeping the Requirement 1 language as is in the July 18th draft is to avoid allowing Transmission Operators from determining the mode in which AVR is to be operated without the need for the process of exempting the generator from operating in AVR in the voltage control mode prior to making the request to the Generator Operator. The new Rationale for R1 does not address the change, but merely includes the proposed changes within the rationale. This is unacceptable and the Standard Drafting Team is asked to expanded the rational for inserting, "or in a different mode, as instructed by the Transmission Operator" into the VAR-002-3 Draft Standard should the request to use the July 18th 2014 draft version of VAR-002-3 not be returned.R2 The requirement references "conditions of notification for deviations from the voltage or Reactive Power schedule." Where are the conditions defined relative to voltage or Reactive Power?R3: The redline version includes an extra "to" in the following sentence, "If the status has been restored within 30 minutes of such change, then to the Generator Operator is not required to notify the Transmission Operator of the status change. Additionally, as currently written the requirement incents a delay in reporting changes in status. Entities should be

<table>
<tr><th>Organization</th><th>Question 1 Comment</th></tr>
<tr><td></td><td>required to report status changes as soon as possible. Allowing entities to not report status changes that reverse within 30 minutes creates a mixed message. Entities may be incented to report status changes at 29 minues and 59 seconds in a hope that the status has been restored.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments. R1 has been modified to provide clarity with regard to AVR settings. R1 clearly states that the AVR must be run in either controlling voltage mode or the mode instructed by the TOP. The only time that the GOP can run in a different mode or in manual is if the GOP has been exempted or the GOP has notified the TOP of one of the bulleted items. Both bullets for R1 still apply to the entire body of R1. The notification conditions will come from the TOP under VAR-001-4.   Also the extra words were removed from R3 and R4. The timing in R3 was added to improve reliability by allowing the GOP to address issues and correct them within the 30 minutes. This would alleviate the TOP from receiving numerous unnecessary notifications.</td></tr>
<tr><td>City of Tallahassee</td><td>1. R3 & R4 - Need to delete the inserted “to” in front of the inserted “the Generator Operator is required to”. (see redline to last posted)2. Table of Compliance Elements (pg 12 of 16, redline to last posted) for R2 under severe VSL, the last paragraph “ The Generator Operator did not modify voltage when directed, and the responsible entity did not provide an explanation” should be modified to be “The Generator Operator did not modify voltage as instructed, and the responsible entity did not provide an explanation” to match the requirement language.</td></tr>
<tr><td colspan="2">Response: Thank you for your comments. The extra words were removed from R3 and R4. The VS for R2 has also been modified.</td></tr>
<tr><td>Tri-State Generation and Transmission Association, Inc.</td><td>The VRF chart in the standard contradicts the language in the requirements. Requirement R5 has the GO as the applicable entity but in the VRF chart it refers to the GOP as the applicable entity. Tri-State believes the GOP should be the applicable entity for requirement R5. Tri-State also believes R5 and R6 should match up and be applicable to the same entities. Thus Tri-State believes the GOP should be the applicable entity for R6.There are also minor edits needed to the requirements below: In R3... If the status has been restored within 30 minutes of such change, then the GOP is not required to notify</td></tr>
</table>

Organization	Question 1 Comment
	the TOP of the status change.In R4... If the capability has been restored within 30 minutes of such change, then the GOP is not required to notify the TOP of the change in reactive capability.
Response: Thank you for your comments. The VSL for R5 has been corrected, and the extra words have been removed from R3 and R4. For R5 and R6, the GO was selected because the owner of the asset is the entity that should have the ultimate responsibility for making those tap changes. The GO will work with the GOP to ensure those change are made.	
Tacoma Power	Tacoma Power submits the following comments: Requirement R4. There is no requirement for GOPs to calculate the baseline reactive capability, so it makes no sense to have R4 require GOPs to notify TOPs when the reactive capability deviates from the baseline reactive capability. Furthermore, the reactive capability of plants can vary in Real-time based on real power output, system voltage, or weather conditions. Per MOD-11 and 12, GOs/GOPs must provide modeling data to the that the TOP can use to evaluate reactive capability. Any notifications under R4 should be limited changes resulting equipment malfunctions. Revise R4 to state “Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to equipment malfunctions other than those malfunctions requiring notification under Requirement R3. If the capability has been restored within 30 minutes of such change, then to the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability.”Requirement R5 is redundant to MOD-011 R1.4 and should therefore be removed from VAR-002-3. Requirement R5.1 does need to include auxiliary transformers because typically system powerflow models do not include unit auxiliary transformers or excitation transformers. If R5.1 is retained, please clarify that auxiliary transformer does not include PTs or CTs.
Response: Thank you for your comments. The standard does not require a baseline calculation, and the currently enforceable VAR-002-2b requires a notification to the TOP as soon as a reactive capability change occurs. Also, the MOD standards are in different time horizons from the VAR standards. R5.1 states “auxiliary transformers with primary voltages equal to or greater	

Organization	Question 1 Comment
than the generator terminal voltage." The drafting team does not believe this encompasses PTs or CTs or excitation transformers.	
Nebraska Public Power District	In Requirement R3 and R4 second sentence, we would suggest the removal of 'to' from the phrase ' then to the Generator' and have it to read as followed: 'then the Generator Operator'. In the last line of the 2nd bullet of R1, insert space between 'Operator' and 'for'.Second bullet of R1 reads: "That the generator is not being operated in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing." The language lends itself to the Generator Operator to not operate in control mode for any reason. We would suggest that the language be tightened up and we suggest the following: "that the generator is not capable of operating in control mode as instructed by the Transmission Operator other than start-up, shutdown, or testing". R4 second sentence: add the words "becoming aware of" between the words "of" and "such".M6: after "Requirment 6" add "and shall have evidence of technical justification as provided in Part 6.1".VSL's R3: add at the end "....of the status change".
Response: Thank you for your comments. The standard has been revised for R2-R4, and the second bullet for R1 has been modified for clarity. R4 has been modified to add the phrase "becoming aware of." The VSLs have also been updated to incorporate your feedback.	

Additional comments received from Doug Hils – Duke Energy:

Duke Energy suggests the following revision to R1 for added clarity on the instants when a GOP can have its AVR in another mode other than controlling voltage:

" 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 unless: 1) the generator is exempted by the Transmission Operator 2) the GOP is instructed by the Transmission Operator to operate in a different control mode or 3) 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 the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing. "

We believe that without this rewording, ambiguity exists of the instances when a GOPs AVR can be different than in service and controlling voltage.

Response: Thank you for your comments. R1 has been modified to provide clarity with regard to AVR settings. R1 clearly states that the AVR must be run in either controlling voltage mode or the mode instructed by the TOP. The only time that the GOP can run in a different mode or in manual is if the GOP has been exempted or the GOP has notified the TOP of one of the bulleted items. Both bullets for R1 still apply to the entire body of R1.

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.
3. Draft standard posted for additional comments and ballot from October 11, 2013 to November 26, 2013.
4. Draft standard posted for additional comments and ballot from February 27, 2014 to April 14, 2014.

Description of Current Draft

This is the fourth posting of the proposed draft standard. This proposed draft standard will be posted for final ballot.

Anticipated Actions	Anticipated Date
Final Ballot	April 2014
NERC Board of Trustees Adoption	May 2014
Filing to Applicable Regulatory Authorities	May 2014

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

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

None.

A. Introduction

1. **Title:** **Generator Operation for Maintaining Network Voltage Schedules**
2. **Number:** VAR-002-3
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**

   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, VAR-002-3 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

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.

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.

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.

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

[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.

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.

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.

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.

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.

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]*

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.

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.

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 transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

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.

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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						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.
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.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						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.

Guidelines and Technical Basis

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

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment on July 19, 2013.
2. Draft standard posted for initial comments and ballot from July 19, 2013 to September 3, 2013.
3. Draft standard posted for additional comments and ballot from October 11, 2013 to November 26, 2013.
4. ~~3.~~ Draft standard posted for additional comments and ballot from February 27, 2014 to April 14, 2014.

Description of Current Draft

This is the ~~third~~ fourth posting of the proposed draft standard. This proposed draft standard will be posted for ~~a 45-day formal~~final ~~comment period and parallel~~ ballot.

Anticipated Actions	Anticipated Date
~~Additional 45-Day SAR Comment Period with Ballot~~	~~February/March~~
Final Ballot	April 2014
NERC Board of Trustees Adoption	May 2014
Filing to Applicable Regulatory Authorities	May 2014

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, and 2.4.3.	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

Definitions of Terms Used in the Standard

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

None.

A. Introduction

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

2. **Number:** VAR-002-3

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**

   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, VAR-002-3 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

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.

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.

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 ~~p~~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.

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

[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.

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 ~~p~~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 ~~p~~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 ~~p~~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~~document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule~~.

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. ~~Such n~~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~~ or capability~~ change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change. ~~The 30-minute window should resolve most issues.~~

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 ~~to~~ 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.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-002~~0~~-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.

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 ~~to~~ 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]*

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.

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 ~~subpart~~ ~~Part~~ 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.

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 transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirement R5, P~~p~~art 5.1.1 through ~~p~~Part 5.1.3 within 30 calendar days.

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.

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, P~~p~~art 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.
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 ~~directed~~ 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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						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.
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 ~~Operator~~ Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 ~~p~~Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator ~~Operator~~ Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 ~~p~~Parts 5.1.1, 5.1.2, and 5.1.3.
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

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it ~~cannot~~ could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001-4 and VAR-002-3

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 – All requirements 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, VAR-001-4 and VAR-002-3 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.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements, the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular jurisdiction in which the new standards are becoming effective.

Implementation Plan

VAR Directives Project

Implementation Plan for VAR-001 and VAR-002

Approvals Required
VAR-001-4 – Voltage and Reactive Control
VAR-002-3 — Generator Operation for Maintaining Network Voltage Schedules

Prerequisite Approvals
There are no other standards that must receive approval prior to the approval of this standard.

Revisions to Glossary Terms
None

Applicable Entities

Generator Operators (VAR-002-3)

Generator Owners (VAR-002-3)

Transmission Operators (VAR-001-4)

~~Reliability Coordinators~~

Applicable Facilities
N/A

Conforming Changes to Other Standards
None

Effective Dates
VAR-001-4 and VAR-002-3 – All requirements ~~– In those jurisdictions where regulatory approval is required, this 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 ~~regulatory approval~~ or as otherwise provided for in a jurisdiction where approval by an~~made effective pursuant to the laws~~ applicable ~~to such ERO~~ governmental authority~~authorities. In those jurisdictions where no regulatory approval~~ is required for a~~, this~~ standard to go into effect. Where approval by an applicable governmental authority is not required, VAR-001-4 and VAR-002-3 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~~approval~~.

Justification

The currently effective VAR-002 standard is one of the most violated standards; however, the industry argues these violations do not address any reliability gaps. Instead, Generator Operators and Transmission Operators are required to handle many nuisance phone calls for slight deviations from a voltage schedule. The nuisance phone calls can be a distraction during a scheduled maintenance or a system event; thus, the industry would support making the changes as soon as possible. However, since VAR-001 now requires determining voltage and reactive power schedules with associated tolerance bands in addition to any notification requirements~~a documented policy or procedure for assessments~~,~~;~~ the Transmission Operators need a quarter to prepare documentation. The VAR-002 standards cannot go into effect without the new TOP schedules and notification requirements. Also for Transmission Operators that do not already provide tolerance bands with voltage schedules, those Transmission Operators will need some time to adjust to providing new data (more specifically, the criteria for schedules) to Generator Operators.

Retirements

VAR-001-3 and VAR-002-2b will be retired at midnight of the day immediately prior to the Effective Date of VAR-001-4 and VAR-002-3 in the particular j~~J~~urisdiction in which the new standards are becoming effective.

Compliance Operations

Draft Reliability Standard Compliance Guidance for VAR-001-4 and VAR-002-3
October 21, 2013

Introduction

The NERC Compliance department (Compliance) worked with the VAR standard drafting team (SDT) to review the proposed standards VAR-001-4 and VAR-002-3. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the VAR SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

VAR-001 and VAR-002 Questions

Question 1

How will compliance determine if sufficient reactive resources were scheduled as part of VAR-001-4 Requirement R2?

Compliance Response to Question 1

For VAR-001-4 Requirement R2, an auditor would review the studies that a TOP used to schedule resources to see that the studies show whether new resources should be brought online, or if the resources online are sufficient to regulate voltage levels. An auditor may observe a TOP reviewing the study and scheduling live and may pull samples from various time periods to determine whether a TOP scheduled resources as required in the study.

Question 2

Is it clear that VAR-001-4 Requirement R4 allows for exemptions, for any duration, from: 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements?

Compliance Response to Question

It is clear that VAR-001 Requirement R4 allows for any combination of exemptions for generator operators from 1) voltage schedules, 2) being in automatic voltage control mode, or 3) any notification requirements, as long as the

exemption meets the criteria specified by the TOP. An auditor will not look for any pre-authorization from the TOP; rather an auditor will verify that the generator operator has met the criteria set forth by the TOP.

Question 3

Tolerance bands apply to a set voltage or Reactive Power number with a +/- percentage as the tolerance band. The voltage range or Reactive Power range is a high and low number that a Generator Operator is expected to operate within for reliability purposes. With regard to VAR-001-4 Requirement R5, is it clear that when a voltage range or Reactive Power range is provided as a schedule, a tolerance band is not expected to also be provided?

Compliance Response to Question 3

Yes, it is clear based on VAR-001-4 Requirement R5 that a voltage or Reactive power schedule can be either: 1) a target number with a tolerance band, OR 2) a voltage or Reactive Power range to operate within. An auditor would not expect to see a tolerance band provided with an operating range for voltage or Reactive Power.

Question 4

With regard to VAR-002-3, will generators receive a violation for instances where a system event is affecting system voltage, but the generators made the appropriate conversions and set the AVRs to meet the original schedule provided by the TOP?

Compliance Response to Question 4

No, the generator operators can only be responsible for maintaining the schedule provided by the TOP based on existing facility equipment. In the event that a generator operator does not have the equipment to have visibility of high-side system voltage, the GOP will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the GOP does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the generator operator is non-compliant. However, if the TOP provides a new directive or schedule, the GOP is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the generator operator is expected to comply pursuant to VAR-002-3.

Question 5

Related to VAR-002-3, generators can monitor voltage on either the low side and high side of the GSU (depending on equipment limitation) and the “number” being monitored by the Generator will not always equate to the number provided by the TOP. Is it clear that VAR-002 Requirement R2, part 2.3 only wants a conversion of the schedule provided to the number monitored? Is it clear that there should not be a violation if the schedule does not match the number being monitored on the low side as long as there is a documented conversion?

Compliance Response to Question 5

The Generator should be able to provide documentation that identifies the "number" being monitored and the calculation demonstrating how the "number" equates to the schedule provided by the TOP. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit.

Question 6

VAR-002-3, Requirement R4 was added because generators cannot report a capability change until they are aware of the change. The currently enforceable standard requires a notification as soon as the capability change occurs; however, many times the change occurred well before the generators were aware of the problem. Is it clear that VAR-002-3 Requirement R4 is only violated after the generator is made aware of the change?

Compliance Response to Question 6

It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the reactive capability change. An auditor will ask an entity for evidence to demonstrate when it became aware of the change in reactive capability. This will not be purely subjective; there are technical instances where it will be clear that an entity would have been made aware of the change in reactive capability. For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

VAR-002 Mapping Document

Transition of VAR-002-2b

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R1	Requirement R1	The requirement has been modified to allow for testing and exemptions for other AVR modes when necessary. This requirement was also modified to allow GOPs to operate in a different control mode as instructed by the TOP.
VAR-002-2b, R2	Requirement R2	The new requirement has been updated to allow for the TOP to define notification requirements. The requirement also adds parts to allow for the conversion of a high side schedule to a low side number for monitoring purposes. Reactive Power schedules have been added for generators that use those schedules, and for consistency purposes “unit” has been changed to “generator”.

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R3	Requirement R3 and R4.	The old requirement has been broken into two requirements: 1) one for AVR/PSS status, and 2) one for reactive capability. Both allow 30 minutes to correct an issue before having to notify the TOP.
VAR-002-2b, R3	Requirement R5	The requirement has been modified to remove the sub-part that requires the GOP to provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." The measure was also modified to add that a GOP must provide the data "within 30 calendar days"
VAR-002-2b, R4	Requirement R6	The requirement has been updated to apply to the same functional entity for the Requirement and sub-part.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

VAR-002 Mapping Document

Transition of VAR-002-2b

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R1	Requirement R1	The requirement has been modified to allow for testing and exemptions for other AVR modes when necessary. This requirement was also modified to allow GOPs to operate in a different control mode as instructed by the TOP.
VAR-002-2b, R2	Requirement R2	The new requirement has been updated to allow for the TOP to define notification requirements. The requirement also adds parts to allow for the conversion of a high side schedule to a low side number for monitoring purposes. Reactive Power schedules have been added for generators that use those schedules, and for consistency purposes “unit” has been changed to “generator”.

NERC

Standard: VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules		
Requirement in Approved Standard	**Transitions to the below Requirement in New Standard or Other Action**	**Description and Change Justification**
VAR-002-2b, R3	Requirement R3 and R4.	The old requirement has been broken into two requirements: 1) one for AVR/PSS status, and 2) one for reactive capability. Both allow ~~15~~ 30 minutes to correct an issue before having to notify the TOP.
VAR-002-2b, R3	Requirement R5	The requirement has ~~not been modified~~been modified to remove the sub-part that requires the GOP to provide "[t]he +/- voltage range with step-change in % for load-tap changing transformers." The measure was also modified to add that a GOP must provide the data "within 30 calendar days"~~.~~
VAR-002-2b, R4	Requirement R6	The requirement has ~~not been modified.~~been updated to apply to the same functional entity for the Requirement and sub-part.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1				X											
R2				X											
R3				X											
R4				X											
R5			X												
R6			X												

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

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 ~~the Generator Operator~~ 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following:

- That the generator is being operated in start-up,[3] shutdown,[4] 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 the ~~automatic voltage~~ 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 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 ~~must~~ 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 ~~it~~ is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

Registered Entity Response to Question (Required):

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this

[3] 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.
[4] 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.
[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M1.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	For instances where entity did not operate a generator in automatic voltage control mode or in a different control mode, as instructed by the Transmission Operator, ensure notification was given to the Transmission Operator in accordance with Requirement R1.

Note to Auditor: Auditors can identify instances where entities did not operate~~d~~ generators ~~outside of~~in automatic voltage control mode, or in a different control mode, as instructed by the Transmission Operator, through their general knowledge of the interconnected transmission system in the entity's area. Auditor knowledge is obtained through activities such as conversations with the entity under audit or the Transmission Operator, and an awareness of events occurring on the interconnected transmission system. In situations where the entity's compliance with this requirement poses little risk to the BES, conversations with other entities, such as Transmission Operators, is most likely not necessary.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule[6] (within each generating Facility's capabilities[7]) 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.

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 ~~directed~~ provided by the Transmission Operator.

2.2. When ~~directed~~ 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 ~~unit~~ 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 ~~directed~~ provided by the Transmission Operator.

For part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's ~~directions~~ instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the

[6] 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.

[7] 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~~ generator is operating in manual control, reactive power capability may change based on stability considerations.

~~direction~~instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For part 2.3, for ~~units~~ Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall document or be able to demonstrate the method of conversion from the voltage level monitored to the voltage level specified on the voltage schedule.

Question: As a Generation Operator, have you operated the generator with the AVR out of service?

Registered Entity Response to Question (Required):

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M2.
Any written policies, procedures or protocols describing how the entity maintains the generator voltage or Reactive Power schedule provided by Transmission Operator, if the entity has such documents.
Generator voltage or Reactive Power schedule provided to entity by Transmission Operator, or entity's record thereof, for timeframes selected by the auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to VAR-002-3, R2
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they maintain the generator voltage or Reactive Power schedule or authorized exemption per Requirement R2.
	Read entity's response to compliance Question above and understand how entity complies with Requirement R2, when they operate a generator with AVR in not in service.
	Select a sample of timeframes during the audit period and have entity walkthrough how they complied with Requirement R2 for those timeframes.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough timeframes, per above, to gain reasonable assurance that entity is complying with Requirement R2.

For part 2.3, the entity should be able to provide documentation that identifies the voltage number being monitored and the calculation demonstrating how it equates to the schedule provided by the Transmission Operator. The measure for VAR-002-3 Requirement R2, part 2.3 is clear on what evidence should be able to demonstrate this during an audit. The entity can only be responsible for maintaining the schedule provided by the Transmission Operator based on existing facility equipment. In the event that an entity does not have the equipment to have visibility of high-side system voltage, the entity will not have the ability to adjust VARs to maintain system voltage. An auditor is not to determine that, where the entity does not have the high side monitoring equipment and where the AVR is set appropriately based on existing facility equipment, the entity is non-compliant. However, if the Transmission Operator provides a new directive or schedule, the entity is required to follow the new directive. This directive can include modifying an AVR setting or providing more voltage support, and the entity is expected to comply pursuant to VAR-002-3.

Auditor Notes:

R3 Supporting Evidence and Documentation

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 ~~the first 15~~30 minutes of such change, then the Generator Operator is not required to ~~there is no need to~~ notify the Transmission Operator of the status change.

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of ~~the~~ any status change identified in Requirement R3. If the status has been restored within the first ~~15~~ 30 minutes, no notification is necessary~~; therefore, if a status change lasts more than 15 minutes, the GOP must notify its associated Transmission Operator within 30 minutes of when the change first occurred~~.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[9]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity responds to a status change on AVR, if the entity has such documents. An example of entity's response to a status change on AVR provided by entity, if applicable.
Auditor may select certain instances where entity had a status change on AVR. In such instances, provide associated evidence of awareness and resolution/notification.
Evidence as outlined in M3.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[9] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to VAR-002-3, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they respond to status changes on AVR.
	Review evidence provided to determine if entity responded to status change on AVR in accordance with Requirement R3.

Note to Auditor: Based on the risk of the entity's compliance with this requirement on the Bulk Electric System (BES) and the auditor's assessment of the entity's management practices (or internal controls) over compliance with this Requirement, auditors will determine the extent of the above audit procedures to apply. In cases where risk to the BES is low and the entity's management practices, gleaned by the auditor through walkthroughs or documentation review, are sound only limited audit testing is necessary. In cases where risk is higher and controls are less effective, an auditor should sample enough timeframes, per above, to gain reasonable assurance that entity is complying with Requirement R3.

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Generator Operator shall notify its associated Transmission Operator within 30 minutes after 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 the first 15 minutes of such change, then there is no need to notify the Transmission Operator.

M4. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of the recognition of a reactive capability change identified in Requirement R4. If the capability has been restored within the first 15 minutes, no notification is necessary; therefore, if a capability change lasts more than 15 minutes, the Generator Operator must notify its associated Transmission Operator within 30 minutes of when the change first occurred.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[10]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Any written policies, procedures or protocols describing how the entity responds to a change in reactive capability, if the entity has such documents. An example of entity's response to a change in reactive capability provided by entity, if applicable.
Auditor may select certain instances where entity ~~should~~ may have been aware of a status change in reactive capability. In such instances, provide associated evidence of awareness and resolution/notification. See Note to Auditor for additional details.
Evidence as outlined in M4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Interview entity staff and/or review documentation provided by the entity to understand how they respond to change in reactive capability.
	Review evidence provided to determine if entity responded to change in reactive capability in accordance with Requirement R4.
Note to Auditor: It is clear that VAR-002-3, Requirement R4 will only be a violation if the change is not reported after 30 minutes of becoming aware of the status change in reactive capability. An auditor will ask an entity for evidence to demonstrate when it became aware of the change. This will not be purely	

[10] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

subjective; there are technical instances (e.g. unit trips, ramping, equipment/AVR failures) where it ~~will be~~is ~~clear~~ likely that an entity ~~would have been~~was made aware of the change in reactive capability. ~~For example, one instance is where a unit is ramping to an expected VAR output, and it cannot reach it; a reactive capability change has occurred.~~

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

5.1. For generator step-up transformers and auxiliary transformers 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 transformers and auxiliary transformers as required in Requirements R5 part 5.1.1 through part 5.1.3.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[11]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
Evidence as outlined in M4. Evidence of transmittal of the data could include, but is not limited to, items such as an electronic message or a transmittal letter with the information included or attached.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted:

[11] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and reply) to determine if entity responded to information request(s) as required in Requirement R5 within 30 days of receiving a request from associated Transmission Operator.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Transmission Operators to determine if requests for data were made or simply confirm the existence of such requests with the entity under audit.	

Auditor Notes:

R6 Supporting Evidence and Documentation

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.

6.1. If the Generator Operator cannot comply with the Transmission Operator's specifications, the Generator Operator 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 as identified in Requirement R6. The Generator Operator 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 as identified in Requirement R6 part 6.1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[12]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
See M6.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to VAR-002-3, R6
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	Review evidence (documented date of request and response) to determine if entity responded to change(s) as required in Requirement R6.
Note to Auditor: Based on the auditors professional judgment, he or she may confirm with Transmission Operators to determine if requests for changes to transformer tap positions were made or simply confirm the existence of such requests with the entity under audit.	

[12] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	11/XX/2013	NERC C~~c~~ompliance, Standards	New Document
2	3/14/2014	NERC Compliance, Standards	Revisions based on changes to underlying Reliability Standard.

Violation Risk Factor and Violation Severity Level Justifications

VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project. A copy of the standard with the associated VRFs and VSLs is available here.

NERC Criteria - Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Violation Risk Factor Guidelines

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

Violation severity levels should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the

Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification – VAR-002-3 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is necessary because this requirement could affect the stability of the BES, but the requirement itself addresses instances where a GOP will not necessarily operate in with the AVR in different control modes or when the TOP will instruct a GOP to operate in other modes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP control modes are not as critical because the TOP is monitoring the system. The companion requirement to VAR-002-3 (in VAR-001-4) are properly designated with a HIGH VRF to ensure voltage schedules are provided as part of the TOPs plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be the same VRFs for VAR-001-4 Requirement R5. VAR-001-4 Requirement R5 requires the TOP to specify a schedule and notification requirements that the GOP must follow.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a GOP not operating in the proper control mode can affect the BES, but a single violation is unlikely to lead to instability, separation, or cascading failure. This is especially the case since a TOP will also be monitoring for voltage deviations.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guideline, this VSL acknowledges the criticality of this requirement and whether or not a system voltage schedule was created.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL because this requirement only has a "severe" VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary, and therefore, a single severe VSL is necessary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirements.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R2 focuses on GOPs maintaining a schedule, but there could be system events that will pull a GOP out of schedule. Also, late at night and early in the morning, the system may experience instances of low or high voltage. This could impact the BES, but a single instance is unlikely to lead to instability, separation, or cascading failure. The sub-requirements also require the GOP to modify the voltage schedule when directed by the TOP.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report lists Reactive Power and voltage control as critical areas where a violation could severely affect the reliability of the Bulk-Power System, there are general times when a GOP will be unable to maintain a voltage schedule due to system condition. These instances occur frequently during the early morning and late at night. The companion requirement to VAR-002-3 (in VAR-001-4) are properly designated

	with a HIGH VRF to ensure voltage schedules are provided as part of the TOP's plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF applies to the entire requirement, including all sub-parts.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: Because maintaining a voltage schedule is critical to preventing a violation of a System Operating Limit, this VRF was drafted to be the same VRFs for VAR-001-4 Requirement R5. VAR-001-4 Requirement R5 requires the TOP to specify a schedule and notification requirements that the GOP must follow.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a GOP not maintaining a schedule can affect the BES, but a single violation is unlikely to lead to instability, separation, or cascading failures. This is especially the case since a TOP will also be monitoring for voltage deviations
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

the Current Level of Compliance	
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for “Binary” Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation,	The proposed VSL is not based on cumulative number of violations.

Not on A Cumulative Number of Violations	

VRF Justification – VAR-002-3 Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement warrants a Medium VRF and is consistent with the NERC definition because this requirement is whether the GOP made the required notifications to the TOP within the appropriate timeframes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP notifications are unlikely to lead to system instability, separation, or cascading failures. This is particularly the case because the TOP is still operating the system to stay within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This VRF is drafted to be consistent with other standards (e.g., BAL) that address making appropriate notifications.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not making the appropriate notifications can impact the grid, but the TOPs are still effectively monitoring the system; thus, instability, separation, or cascading failures are unlikely due to a single violation.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-002-3 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the standard is violated only when a notification is not made to the TOP; therefore, a severe VSL is warranted. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be	The proposed VSL is worded consistently with the corresponding requirement.

Consistent with the Corresponding Requirement	
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	This requirement warrants a Medium VRF and is consistent with the NERC definition because this requirement is whether the GOP made the required notifications to the TOP within the appropriate timeframes.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although the Blackout Report list Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, the GOP notifications are unlikely to lead to system instability, separation, or cascading failures. This is particularly the case because the TOP is still operating the system to stay within System Operating Limits and Interconnection Reliability Operating Limits.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: There is no sub-part to Requirement 3; therefore, the requirement is consistent.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: This VRF is drafted to be consistent with other standards (e.g., BAL) that address making appropriate notifications.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because not making the appropriate notifications can impact the grid, but the TOPs are still effectively monitoring the system; thus, instability, separation, or cascading failures are unlikely due to a single violation.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level

VSL Justification – VAR-002-3 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the standard is violated only when a notification is not made to the TOP; therefore, a severe VSL is warranted.

"Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – VAR-002-3 Requirement R5	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is a Lower VRF because the tap setting data does not change frequently, and a violation is not expected adversely affect the BES.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement would not adversely impact the BES

	if violated. The tap information is provided during interconnection, and it is not expected to change frequently. Therefore, a Lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The parts within Requirement R5 are consistent with Requirement R5 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: There are no other standards that address Tap settings.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation is similar to an administrative violation. Further, since tap settings are infrequently changed, a violation would not adversely impact the BES.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation: This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

the Current Level of Compliance	
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for “Binary” Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation,	The proposed VSL is not based on cumulative number of violations.

Not on A Cumulative Number of Violations	

VRF Justification – VAR-002-3 Requirement R6	
Proposed VRF	**Lower**
NERC VRF Discussion	This requirement is a Lower VRF because the tap setting data does not change frequently, and a violation is not expected adversely affect the BES.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: Although Reactive Power and voltage control are part of the list of critical areas where a violation could severely affect the reliability of the Bulk-Power System, this requirement would not adversely impact the BES if violated. The tap information is provided during interconnection, and it is not expected to change frequently. If a violation were to occur, the system would still operate at the level prior to making any tap setting changes. Therefore, a Lower VRF is warranted.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The part within Requirement R6 is consistent with Requirement R6 and is considered a Lower VRF.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: There are no other standards that address Tap settings.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: This VRF is consistent with the NERC Definition because a violation is similar to an administrative violation. Further, since tap settings are infrequently changed, a violation would not adversely impact the BES.
FERC VRF G5 Discussion	Guideline 5 - Treatment of Requirements that Co-mingle More Than One Obligation:

	This VRF does not co-mingle multiple objectives, nor does it water down the Requirement to reflect a lower risk level.

VSL Justification – VAR-002-3 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines. The VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is binary because the requirement focuses on whether tap changes were made. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-002-3

Final Ballot Now Open through May 5, 2014

Now Available

A final ballot for **VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules** is open through **8 p.m. Eastern on Monday, May 5, 2014.**

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

Instructions for Balloting

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2013-04 Voltage and Reactive Control
VAR-002-3

Final Ballot Results

Now Available

A final ballot for **VAR-002-3 – Generator Operation for Maintaining Network Voltage Schedules** concluded at **8 p.m. Eastern on Monday, May 5, 2014.**

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Standard	Quorum / Approval
VAR-002-3	83.84% / 88.26%

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

Next Steps

The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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

Ballot Results	
Ballot Name:	Project 2013-04 Voltage and Reactive Control VAR-002-3
Ballot Period:	4/23/2014 - 5/5/2014
Ballot Type:	Final
Total # Votes:	332
Total Ballot Pool:	396
Quorum:	**83.84 % The Quorum has been reached**
Weighted Segment Vote:	88.26 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	106	1	65	0.867	10	0.133	0	9	22
2 - Segment 2	9	0.6	6	0.6	0	0	0	3	0
3 - Segment 3	86	1	62	0.873	9	0.127	0	4	11
4 - Segment 4	30	1	22	0.786	6	0.214	0	1	1
5 - Segment 5	98	1	55	0.809	13	0.191	0	7	23
6 - Segment 6	52	1	39	0.867	6	0.133	0	3	4
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 -									

Segment 9	3	0.2	2	0.2	0	0	0	0	1
10 - Segment 10	8	0.7	7	0.7	0	0	0	0	1
Totals	**396**	**6.8**	**261**	**6.002**	**44**	**0.798**	**0**	**27**	**64**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Negative	COMMENT RECEIVED
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS
1	El Paso Electric Company	Pablo Onate	Abstain	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	

1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke		
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Abstain	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Abstain	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	

2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	Supports FirstEnergy's comments
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	

3	Oklahoma Gas and Electric Co.	Donald Hargrove	Abstain	
3	Old Dominion Electric Coop.	Bill Watson		
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	COMMENT RECEIVED
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Wisconsin Public Service Corp.	Gregory J Le Grave		
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	SUPPORTS THIRD PARTY COMMENTS
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Negative	
4	Consumers Energy Company	Tracy Goble		
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney	Affirmative	

4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BP Wind Energy North America Inc	Carla Holly	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Calpine Corporation	Hamid Zakery	Affirmative	
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	El Paso Electric Company	Gustavo Estrada	Abstain	
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Negative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Lafayette Utilities System	Jamie B Webb	Abstain	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED

5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua	Abstain	
5	PacifiCorp	Bonnie Marino-Blair		
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Vandolah Power Company L.L.C.	Douglas A. Jensen		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS
6	FirstEnergy Solutions	Kevin Querry	Affirmative	

6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Abstain	
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Central Lincoln PUD	Bruce Lovelin	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones		
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Exhibit G

Standard Drafting Team Roster

Drafting Team Members and Observers for VAR

Name and Title	Company	Contact Info	Bio
Bill Harm, Chair	PJM Interconnection	(610) 666-8868 harm@pjm.com	Bill Harm is a Senior Consultant at PJM in the NERC and regional coordination department. Bill has over 39 years of experience in various aspects of the planning and operation of the PJM network. Before joining the NERC and regional coordination department Bill worked in operations, operations planning, system planning and operations support. Bill's background also includes technical support of operations and markets during the integration of new members into the PJM market as well as developing various joint operating agreements. Bill Harm has also participated in the follow NERC activities: • NERC Systems Analysis and Modeling Subcommittee • NERC Modifications to FAC-012 and FAC-013 for Order 729 • NERC ATC SAR Drafting team • ERAG Management Committee • MEN/VEM study Committees • Joint Inter regional Review Committee • NERC 2003 Blackout Investigation Team
Martin Kaufman, Vice Chair	ExxonMobil Research and Engineering	(281) 834-7549 martin.kaufman@exxonmobil.com	Martin Kaufman is experienced in industrial electric system design, operation, and configuration; including cogeneration facility operation and design, and an in-depth understanding of the supply needs of large end-users and how the operation and planning of the bulk power system impacts these needs. Martin Kaufman currently performs a global power system design and operation subject matter expert role for ExxonMobil, and provides compliance assurance support for NERC activities.

Name and Title	Company	Contact Info	Bio
Scott Berry	Indiana Municipal Power Agency	317-428-6710 sberry@impa.com	Scott Berry has 21 years of Generator experience which include, 6 years in the Navy Nuclear Power Program as a Reactor Operator and 15 years with Gas Combustion turbines as an Operator. Scott has also served as a Technician and Plant Superintendent, and he has been working with NERC and regional standards for approximately 6 years. Scott is currently active in the following areas: Transmission Access Study Group (TAPS); Small Entity Working Group (RFC and SERC Entities); North American Generator Forum; and Combustion Turbine Operation Task Force (CTOTF).
Brian Buckley	TECO Energy	bsbuckley@tecoenergy.com	Brian Buckley is the Manager of Compliance and Performance responsible for leading all Energy Supply regulatory activities including our Compliance Program for FERC, NERC and FRCC standards. Brian received a Bachelor of Science degree in Mechanical Engineering in 1997 from the Georgia Institute of Technology and a Master of Business Administration from the University of South Florida in 2003. Brian's past positions at Tampa Electric include: Operations Engineer at Gannon/Bayside Station (a natural gas combined cycle plant), Instrumentation and Controls Engineer at Big Bend Station (a coal-fired plant), and Senior Engineer in Operations Planning (maintaining reliability of all company plants).

Name and Title	Company	Contact Info	Bio
Steve Hitchens	Bonneville Power Administration	509-465-0339 sbhitchens@bpa.gov	Steve Hitchens is an Electrical Engineer with Bonneville Power Administration since 1991. Steve served for six years with substation Design, outdoor design for high voltage substations. From 1997 to present , Steve has worked as the Technical Operations Engineer responsible for: • Seasonal and outage planning studies for determining SOL's on the major BPA interchanges and flowgates; • BPA Dispatch support for main grid and sub grid operation; • NERC VAR-001 SME for Requirements R2, R3, R4, R6 and R11; and • Reactive and Voltage SME (since 2004) responsible for, in part, the BPA Voltage Schedule updates, modifications and circulation
Sharma Kolluri	SERC	(504) 576-4045 vkollur@entergy.com	Sharma Kolluri has over 30 years of experience in the Planning and Operation areas. He is currently the Manager of Transmission Planning at Entergy where is responsible for stability studies, reactive power planning studies, reactive power management and generator interconnection studies. Sharma is responsible for reactive power planning and management studies at Entergy. He has also published several papers at IEEE in the area of reactive power planning and voltage stability, especially dealing with static and dynamic reactive power compensation. He served as a past chairman of the Dynamics Review Sub Committee (DRS) at SERC, and he is a member of the IEEE Dynamic Performance Committee, Stability Controls sub-committee and Voltage stability task force.

Name and Title	Company	Contact Info	Bio
Joshua Pierce	Southern Company Services-Transmission Planning	205-257-6196 jspierce@southernco.com	Joshua Pierce has worked for Southern Company for more than ten years with extensive experience within the transmission organization of a vertically integrated utility. He began his career with Southern Company in 2002 as a student engineer in Transmission Line Design and Maintenance Support for Alabama Power Company (APC). He began full time employment in 2004 in APC Substation Protective Equipment and Controls Design and joined APC Substation Protection and Control Field Services in 2008. In 2011, he joined Transmission Planning for Southern Company Services where he presently works performing tariff generator interconnection and transmission service studies as well as regional planning.

Name and Title	Company	Contact Info	Bio
Joe Seabrook	Puget Sound Energy	(425) 462-3577 Joe.Seabrook@pse.com	Joe Seabrook has worked in transmission expansion planning and operating at Puget Sound Energy since 1980. Puget's transmission and transmission rights extend from Washington State to Canada, through Montana, and south to the Oregon-California border. Joe is currently chairing a WECC working group to add SPS, relays, contingency descriptions, sequence components and breaker-node topology to WECC planning and operating base cases. Joe also helped develop the reactive margin requirements and voltage stability assessment methodology used by WECC, and he co-authored WECC reports, studies, guidelines, methodology, and criteria on voltage stability, reactive margin, and under voltage load tripping beginning in 1994. Joe has served on the WECC Technical Studies Subcommittee since 1993, serving as the chair, vice-chair, and secretary, and leading and serving many work groups and task forces on reliability criteria, transmission path rating, off-nominal frequency, under voltage generator and load issues, and synchronous and wind generator dynamic modeling. Joe also helped develop the reactive margin requirements and voltage stability assessment methodology used by WECC. This began with the original report in 1997 that was used to develop the WECC reactive margin criteria requirements in 2002, and the WECC Safety Net policy.

Name and Title	Company	Contact Info	Bio
Hari Singh	Xcel Energy	(303) 571-7095 hari.singh@xcelenergy.com	Hari Singh has been a member of the NERC Transmission Issues Subcommittee (TIS) since 2009. Hari is also a member of the WECC Modeling & Validation Working Group (MVWG) and well versed with the composite load model being developed and tested by WECC MVWG for promoting improved dynamic load modeling to study FIDVR events and/or evaluate voltage stability in load centers to identify the need for implementing UVLS. Currently, Hari serves as the Transmission Planning Engineer responsible for conducting the periodic studies required by PRC-010 to assess the need for UVLS or the effectiveness of existing UVLS. Hari is also a member of the NERC System Analysis & Modeling Subcommittee and the WECC Reliability Subcommittee. He has also served as the WECC Modeling & Validation WG Technical Consultant to Rocky Mountain Voltage Coordination Guidelines Working Group.
Mike Swearingen	Tri-country Electric Cooperative, Inc.	580-652-3804 mikeswearingen@tri-countyelectric.coop	Mike Swearingen has over 19 years of experience as a power system engineer for transmission and distribution systems. Mike designed and oversaw the design and construction of substations and mobile substations. He also has field experience in power system operation and control systems. Mike has also participated in the IEEE Power Quality Subcommittee and associated working groups by helping in the development of standards. Further, Mike developed the NERC program and Internal Compliance Program for Tri-County Electric Cooperative

Name and Title	Company	Contact Info	Bio
Hamid Zakery	Calpine Corporation	(832) 325-5007 hamid.zakery@calpine.com	For the past 28 years, Hamid Zakery have served the utility industry in various technical and operation responsibilities. Hamid started his career with Illinois Power Company as a relay engineer where he designed protection schemes for Transmission, Distribution and Generation assets. Later he became responsible for operation and maintenance activities for utility substations ranging from 480 volts to 345 Kv systems. As a plant engineering manager, Hamid held responsibilities for fossil plants engineering functions including performance and predictive maintenance. Over the past 10 years, he has been involved with development and implementation of engineering, operation and maintenance programs to prepare IPP generation assets in all 8 NERC Regions for compliance with NERC standards and regional guidelines.