NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 5, 2009

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation,*
Docket No. RM06-16-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations seeking approval for an interpretation of the requirements in Commission-approved NERC Reliability Standard VAR-002-1a[1] — Generator Operation for Maintaining Network Voltage Schedules that is contained in **Exhibit A** to this petition.

The formal interpretation provided in this filing was approved by the NERC Board of Trustees on February 10, 2009. NERC requests that this interpretation be made effective immediately upon approval by the Commission.

[1] At the time the request for interpretation was made, VAR-002-1 was the approved Reliability Standard on record with the Commission. Subsequently. The NERC Board of Trustees approved on August 1, 2007 and the Commission approved an interpretation to Requirements R1 and R2 of VAR-002-1 on July 21, 2008. NERC renumbered the standard as VAR-002-1a to reflect the addition of the interpretation. NERC then approved an errata change for VAR-002-1a on October 29, 2008 that it filed for Commission approval on February 6, 2009 as VAR-002-1.1a. Accordingly, the interpretation that is the subject of this filing will be appended to the standard and labeled as VAR-002-1.1b.

NERC's petition consists of the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the formal interpretation meets the reliability goal of the standard involved;
- Formal interpretation submitted for approval (**Exhibit A**);
- Reliability Standard VAR-002-1.1b that includes the appended interpretation (**Exhibit B**); and
- The complete development record of the formal interpretation (**Exhibit C**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Rebecca J. Michael

Rebecca J. Michael

Assistant General Counsel for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM06-16-000)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF FORMAL INTERPRETATION TO RELIABILITY STANDARD VAR-002-1a – GENERATOR OPERATION FOR MAINTAINING NETWORK VOLTAGE SCHEDULES

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[2] hereby requests the Federal Energy Regulatory Commission (the "Commission" or "FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA" or the "Act")[3] and Section 39.5 of the Commission's regulations, 18 C.F.R. § 39.5, an interpretation to a requirement of a Commission-approved NERC Reliability Standard:

– VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules

No modifications to the language contained in this Standard are being proposed through the interpretation.

The NERC Board of Trustees approved the formal interpretation to VAR-002-1a-Generator Operation or Maintaining Network Voltage Schedules on February 10, 2009. NERC requests that the Commission approve this formal interpretation and make it effective immediately after approval in accordance with the Commission's procedures. **Exhibit A** to this filing sets forth the formal interpretation. **Exhibit B** contains the affected Reliability Standard containing the appended interpretation. **Exhibit C** contains the complete development record of the formal interpretation to the Reliability Standard requirement.

NERC also is filing this formal interpretation with applicable governmental authorities in Canada.

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[2] NERC was certified by the Commission as the electric reliability organization ("ERO") authorized under Section 215 of the Federal Power Act. The Commission certified NERC as the ERO in its Order issued July 20, 2006, in Docket No. RR06-1-000. *See Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[3] 16 U.S.C. 824o.

II. NOTICES AND COMMUNICATIONS

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

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*Persons to be included on the Commission's service list are indicated with an asterisk.

III. BACKGROUND

a. Regulatory Framework

Congress, through its enactment of the Energy Policy Act of 2005 (the "Act"),[4] entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 of the Act states that all users, owners and operators of the bulk power system in the United States will be subject to Commission-approved Reliability Standards.

[4] Energy Policy Act of 2005, 16 U.S.C. §824o, Pub. L. No. 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005).

b. Basis for Approval of Proposed Interpretation

While this formal interpretation does not represent new or modified Reliability Standard requirements, it does provide formal instruction regarding the intent, and, in some cases, the application of the requirement in order to provide guidance to assist parties in their compliance with the Reliability Standards. Accordingly, NERC requests Commission approval of the interpretation.

c. Reliability Standards Development Procedure and Interpretation

All persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of NERC Reliability Standards, as discussed in NERC's *Reliability Standards Development Procedure*.[5] Upon request, NERC will assemble a team with the relevant expertise to address the interpretation request and, within 45 days, will present a formal interpretation for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation will be appended to the Reliability Standard and filed for approval with the Commission and the appropriate governmental authorities in Canada to be made effective when approved. When the affected Reliability Standard is next revised using the Reliability Standards Development Process, the interpretation will then be incorporated into the Reliability Standard.

The formal interpretation set out in **Exhibit A** has been developed and approved by industry stakeholders using NERC's *Reliability Standards Development Procedure*. It

[5] *See* NERC's *Reliability Standards Development Procedure*, Approved by the NERC Board of Trustees on March 12, 2007, and Effective June 7, 2007 ("Reliability Standards Development Procedure"), available at http://www.nerc.com/files/Appendix3A_StandardsDevelopmentProcess.pdf.

was approved by the NERC Board of Trustees through the process explained above on February 10, 2009.[6]

IV. VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules

The Commission approved Reliability Standard VAR-002-1 in Order No. 693.[7] On August 1, 2007, the NERC Board of Trustees approved the interpretations of Requirements R1 and R2 of Reliability Standard VAR-002-1, which is included as Appendix 1 of the Reliability Standard. NERC changed the standard number to VAR-002-1a, in order to recognize the interpretation being added to the standard. The Commission approved this Reliability Standard interpretation on July 21, 2008. On February 6, 2009, NERC submitted VAR-002-1.1a to the Commission for approval, in order to address errata changes identified in the Reliability Standard. The present filing includes the Reliability Standard, as well as the current proposed interpretation and the previous Commission-approved interpretation with errata changes. It is labeled as VAR-002-1.1b, and is included in **Exhibit B.**

In Section IV (a), below, NERC discusses the proposed interpretation to the standard, and explains the need for the development of formal interpretation to the requirements in VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules. In this discussion, NERC demonstrates that the formal interpretation is consistent with the stated reliability goals of the Commission-approved Reliability

[6] The Commission issued an Order on July 21, 2008 that approved five modified Reliability Standards and interpretations to five requirements of Commission-approved Reliability Standards. In footnote 8 of this Order, the Commission expresses concern that NERC's Rules of Procedure are silent with regard to NERC Board of Trustees approval of interpretations of Reliability Standards. While NERC believes that Version 6.1 of its *Reliability Standards Development Procedure* addresses this issue, NERC will propose an amendment to its Rules of Procedure to make more explicit the Board of Trustees' expectations with respect to approval of formal interpretations of Reliability Standards, thereby addressing the Commission's concerns.

[7] Order No. 693 at P 1884 and Appendix A.

Standards and the requirements thereunder. Set forth in Section IV(b) below, are the stakeholder ballot results and an explanation of how stakeholder comments were considered and addressed by the Reliability Standards drafting team assembled to provide the interpretation.

The complete development record for the interpretation is set forth in **Exhibit C**, and includes the request for interpretation, the response to the request for interpretation, the ballot pool, the final ballot results by registered ballot body members, stakeholder comments received during the balloting and a discussion of how those comments were considered.

a. Justification for Approval of Formal Interpretation

The stated purpose of VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules is "[t]o 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." There are five requirements in Reliability Standard VAR-002-1 that apply to Generator Operators and/or Generator Owners. The specific language of these Requirements is:

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[8]) as directed by the Transmission Operator.

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

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

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

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

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

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

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

On June 16, 2008, ICF Consulting ("ICF") requested that NERC provide a formal interpretation of Reliability Standard VAR-002-1a — Generator Operation for

Maintaining Network Voltage Schedules.[9] In its request, ICF asked NERC to "identify which requirements apply to generators that do not operate generators equipped with automatic voltage regulators ("AVRs")."[10] ICF asserted that "[c]onfusion 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."[11] ICF questioned whether this standard requires Generator Owners to acquire AVR devices where they did not previously exist to comply with the Requirements of Reliability Standard VAR-002-1a.

NERC assigned its Phase III and IV and Generator Verification Standard Drafting Team ("Phase III/IV SDT") to provide the requested interpretation, which found that all "the requirements and associated sub requirements 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."[12] The Phase III/IV SDT further found that "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."[13]

The Phase III/IV SDT asserted in its interpretation that "the requirements and associated sub requirements 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 (AVR) that is capable of automatic operation. A generator that is not

[9] This is item # 2 in the Record of Development.
[10] This is item # 2 in the Record of Development.
[11] This is item # 2 in the Record of Development.
[12] This is item # 1 in the Record of Development.
[13] This is item # 2 in the Record of Development.

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."

The Phase III/IV SDT also found that the standard does not require a generator to be equipped with, or be modified to add, an AVR. Requirement R1 compels Generator Operators to notify their Transmission Operator(s) when automatic voltage control capability is not available, which may be due to the AVR not functioning or the absence of one. In the instance a unit is not equipped with an AVR, the Generator Operator of the unit is required to inform its Transmission Operator that the generator is not capable of automatic voltage control. In accordance with Requirement R2 of the standard, all Generator Operators (unless exempted by the Transmission Operator) are required to maintain their generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by their Transmission Operator(s).

VAR-002-1, Requirement R2 also provides the Transmission Operator the ability to exempt generators from maintaining their assigned generator voltage or Reactive Power Requirements schedule in some circumstances. Requirement R2 of the standard allows the Transmission Operator to consider information provided by the Generator Operator, in accordance with Requirements R1 and R2, explaining that the generator is not AVR equipped.

In sub-requirement R2.1, the Generator Operator is provided an option to use alternative methods when the AVR is out of service. The Phase III/IV SDT further clarified this action is intended to control voltage or Reactive Power in order to accomplish the desired result of meeting the voltage schedule. This sub-requirement

applies to a generator regardless of whether it is equipped with an out of service AVR or no AVR at all.

Similarly, sub-requirement R2.2 applies independent of whether an AVR is present. Sub-requirement R2.2 provides that a Generator Operator shall either comply with or provide an explanation regarding why the Transmission Operator directed voltage schedule cannot be met.

The Phase III/IV SDT explained that in the case of generators not equipped with an AVR, Requirement R3 and associated sub requirements require the Generator Operator to notify the Transmission Operator if and when such capability is installed or if the range of a unit's reactive capability is different than what is modeled or understood by the Transmission Operator. The drafting team continued by stating that, with respect to Requirements R4 and R5, all Generator Operators must comply with these Reliability Standard requirements regardless of whether an AVR system is present.

NERC offers the following additional information not contained in the interpretation response to add further context to the discussion regarding the provision of dynamic reactive response through AVR. Reliability Standard VAR-002-1a does not explicitly identify the need for all generators to have AVR installed. However, the reliability objective to have sufficient dynamic reactive response is clearly articulated in several other NERC Reliability Standards that, on the aggregate, provide the motivation for AVRs or other types of dynamic reactive capability to be installed.

The Transmission Planner in the first instance is obligated to ensure that the system, at minimum, meets the performance expectations outlined in the TPL-001 through TPL-004 Reliability Standards. This evaluation in the long-term obligates the

Transmission Planner to identify where dynamic reactive support is required to permit the appropriate system response in accordance with Table 1 of the aforementioned standards. To the extent that insufficient dynamic reactive response is available to meet the performance expectations, the Transmission Planner must develop a Mitigation Plan to address the noted deficiencies. One option, and one most common in industry application, is to coordinate with the appropriate generator owners to install AVR equipment to permit system response in such a manner that would ensure compliance with the TPL reliability standards. This activity does not suggest or imply that AVR is required everywhere across the system, but it does permit discretion in its application to support the performance expectations in the TPL standards.

In addition, Transmission Owners are required to establish facility interconnection requirements in accordance with Reliability Standard FAC-001 — Facility Connection Requirements. In particular, Requirement R1 provides:

> **R1.** The Transmission Owner shall document, maintain, and publish facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Reliability Organization, subregional, Power Pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:
>
> **R1.1.** Generation facilities,

Requirement R2 then states:

> **R2.** The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:
>
> **R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
>
> **R2.1.1.** Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.
R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.
R2.1.4. Breaker duty and surge protection.
R2.1.5. System protection and coordination.
R2.1.6. Metering and telecommunications.
R2.1.7. Grounding and safety issues.
R2.1.8. Insulation and insulation coordination.
R2.1.9. Voltage, Reactive Power, and power factor control.
R2.1.10. Power quality impacts.
R2.1.11. Equipment Ratings.
R2.1.12. Synchronizing of facilities.
R2.1.13. Maintenance coordination.
R2.1.14. Operational issues (abnormal frequency and voltages).
R2.1.15. Inspection requirements for existing or new facilities.
R2.1.16. Communications and procedures during normal and emergency operating conditions.

These requirements provide the basis for establishing generator facility interconnection expectations in a manner that would assist the Transmission Owner in meeting the system performance expectations defined in the NERC Reliability Standards. These expectations are specifically highlighted in Reliability Standard FAC-00-1-0, Requirements R2.1.3, R2.1.9 and R2.1.14.

Reliability Standard FAC-002-0 — Coordination of Plans for New Facilities provides that in order to "avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements." FAC-002-0, Requirement R1 and its subparts include the obligations necessary to ensure acceptable system performance in accordance with NERC Reliability Standards for new facilities intending to interconnect to the grid. These requirements state:

R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission

facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:

R1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.
R1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.
R1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.
R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance in accordance with Reliability Standard TPL-001-0.
R1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

While the foregoing discussion emphasizes the need for the Transmission Owner and the Transmission Planner to assess system performance with respect to the interconnection of new facilities, to identify the requirements to interconnect in support of system performance expectations, and to develop joint recommendations to meet these expectations in the long-range planning horizon, there are a series of requirements in Reliability Standard VAR-001-1.1a — Voltage and Reactive Control Reliability Standard that addresses this similar expectation in the operations horizon. Specifically, VAR-001-1.1a, Requirements R2 and R8 through R12 define these obligations.

Requirements R2 and R8 through R12 provide:

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

***

R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.

R9. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.

R9.1. Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.

R10. Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.

R11. After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.

R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

FAC-002-0, Requirement R2 discusses reactive sufficiency under normal and Contingency conditions. FAC-002-0, Requirement R8 requires the Transmission Operator to operate reactive resources up to, and including, load shedding to maintain voltages within limits. FAC-002-0, Requirement R9 specifically identifies the need to locate and maintain reactive support under first Contingency conditions. FAC-002-0, Requirement R10 addresses limit violations, including interconnection reliability operating limits ("IROLs"), resulting from insufficient reactive support. FAC-002-0, Requirement R11 requires interaction with the Generator Operator to properly set generator step-up transformer tap settings in order to optimize the ability to actively utilize unit reactive output and to maintain reserves in concert with other transmission

system level reactive resources. Finally, FAC-002-0, Requirement R12 directs the Transmission Operator to take preemptive action to prevent voltage collapse. In sum, this set of requirements directs the Transmission Operator to understand the dynamics of its footprint so that voltage sufficiency and stability are maintained under normal and contingency conditions, and importantly, so that the needed resources to ensure adequate system performance are obtained.

On an ongoing basis, the Transmission Operator is responsible for monitoring the transmission system and identifying reactive deficient locations on the grid where additional reactive support is necessary to help it achieve the performance expectations outlined in Reliability Standard VAR-001-1. This insight is useful not only in identifying where and when dynamic reactive support is needed, but also in triggering efforts, while working with the Transmission Planners and Transmission Owners, to add AVR equipment on equipment not currently so equipped, or in adding transmission devices such as static VAR compensators, or something similar.

b. Summary of the Reliability Standard Development Proceedings

On June 16, 2008, ICF Consulting requested a formal interpretation of Reliability Standard VAR-002-1a--Generator Operation for Maintaining Network Voltage Schedules. In accordance with its *Reliability Standards Development Procedure*, NERC posted its response to the request for interpretation for a 30-day pre-ballot period that took place from August 7, 2008 to September 8, 2008. NERC conducted an initial ballot from September 9, 2008 to September 17, 2008. In that initial ballot, 85.78% of the total ballot pool cast a vote. The interpretation received a weighted segment approval of 90.37% but included 12 negative votes with associated comments, triggering the need for

a recirculation ballot. After the Phase III/IV SDT drafting team responded to the comments, NERC conducted a 10-day recirculation ballot from January 6, 2009 until January 15, 2009. The formal interpretation was approved by the ballot pool with a weighted segment average of 91.21%, with 91.47% of the ballot pool voting.

In the comment period, several balloters indicated that the interpretation may be read as "requiring" that AVR is required, even if not installed at a facility. In response, the team noted that the interpretation states that "[t]he standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. The standard has no stated requirement that each generator shall be equipped with an AVR."

Several balloters asked for clarification on how to acquire an "exemption" from the Transmission Operator. This interpretation will not include any additional information on this request for clarification, such as how exemptions are determined or implemented, as the request is out of the scope of this interpretation process. However, NERC notes that Reliability Standard VAR-001-1a, Requirement R3 requires the Transmission Operator to identify criteria for exempting generators from compliance with the requirements (defined in VAR-001-1a, Requirement R4) to comply with the voltage schedule (provided by the Transmission Operator) in automatic voltage control mode and the requirements (defined in VAR-001-1a, Requirement R6) to maintain or change voltage or reactive power schedules (provided by the Transmission Operator).

Some balloters also indicated that this interpretation does not support the "original" intent of the predecessor Planning Standard, and stated that the original intent of the predecessor standard was to require all generators to have AVR and operate in the

automatic mode. The original Planning Standard used as a basis for Version 0 was III.C.S1 which stated, "All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator."[14] Neither the current standard nor the interpretation state or reference this "intention".

Some balloters indicated that interpretation should be posted for comment before being balloted. This process issue is being addressed by the NERC Standards Committee.

The Phase III/IV SDT drafting team did not make any modifications to the interpretation based on the comments received.

[14] This is item # 6 in the Record of Development.

V. CONCLUSION

NERC requests that the Commission approve the formal interpretation to the following requirements in the Commission-approved NERC Reliability Standards:

- VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules.

As set out in **Exhibit A**, in accordance with Section 215(d)(1) of the FPA and Part 39.5 of the Commission's regulations. NERC requests that the interpretation be made effective immediately upon approval.

Respectfully submitted,

/s/ Rebecca J. Michael

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 5th day of March, 2009.

/s/ Rebecca J. Michael
Rebecca J. Michael

Attorney for North American Electric Reliability Corporation

Exhibit A

Formal interpretation submitted for approval

VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules (Project 2008-11)

Request for Interpretation Received from ICF Consulting on June 16, 2008:

ICF Consulting's June 16, 2008 request for a formal interpretation of VAR-002-1a states:

"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."

VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

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

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

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

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

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

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

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

The following interpretation of VAR-002-1a was developed by a subset of the members of the Phase III and IV and Generator Verification standard drafting teams on July 29, 2008:

Please note that the interpretation response cites version 1a of VAR-002 as the ICF request did not specify a version.

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.

Background and Discussion

VAR-002-1a is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. Considered in the context that an out of service automatic voltage regulator and the lack thereof are functionally equivalent conditions will aid in the understanding of the intent of the requirements in VAR-002-1a.

The following explains how to interpret the requirements:

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. (underline emphasis added)

The intent of Requirement R1 is for the Generator Operator to inform its Transmission Operator that automatic voltage control capability is not available, which may be due to the automatic voltage regulator not functioning or the absence of one. Generator Operators operating generators not equipped with an automatic voltage regulator simply must inform the Transmission Operator that the generator is not capable of automatic voltage control.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings1) as directed by the Transmission Operator.

R2.1. *When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.*

R2.2. *When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.*

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

Requirement R2 allows a Transmission Operator to exempt generators from maintaining a generator voltage or Reactive Power output schedule.

Requirement R2.1 states that the Generator Operator must control voltage and reactive output in accordance with the schedule provided by the Transmission Operator using alternative methods when the automatic voltage regulator is not available. The action required is to control voltage or Reactive Power and the desired result is for the voltage schedule to be met. This requirement

applies to a generator irrespective of whether it is equipped with an out of service automatic voltage regulator or no automatic voltage regulator at all.

Requirement R2.2 is independent of the presence of an automatic voltage regulator and does allow the Generator Operator without an automatic voltage regulator to provide an explanation for not being able to comply with the Transmission Operator directed voltage schedule.

Similarly, Requirement R2 is also independent of the presence of an automatic voltage regulator but does allow the Transmission Operator to consider information provided by the Generator Operator in accordance with R1 and possibly R2.2 regarding the fact that the generator is not automatic voltage regulator equipped.

R3. *Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:*

R3.1. *A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.*

R3.2. *A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.*

In the case of generators not equipped with an automatic voltage regulator, Requirement R3 and associated sub-requirements simply require the Generator Operator to inform the Transmission Operator if and when such capability is installed.

R4. *The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.*

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

R4.1.1. *Tap settings.*
R4.1.2. *Available fixed tap ranges.*
R4.1.3. *Impedance data.*
R4.1.4. *The +/- voltage range with step-change in % for load-tap changing transformers.*

R5. *After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.*

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

Whether or not a generator is equipped with an automatic voltage regulator is not relevant to either Requirement R4 or Requirement R5 Generator Operators of all generators without an automatic voltage regulator must comply.

Exhibit B

Affected Reliability Standard that includes the appended interpretation

VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

Standard VAR-002-1.1b — Generator Operation for Maintaining Network Voltage Schedules

A. Introduction

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

2. Number: VAR-002-1.1b

3. Purpose: To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.

4. Applicability

4.1. Generator Operator.

4.2. Generator Owner.

5. Effective Date: Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

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

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

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

R4.1.3. Impedance data.

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

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

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

C. Measures

M1. The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.

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

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

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

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

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

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

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

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

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

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

1.4. Additional Compliance Information

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

2. Levels of Non-Compliance for Generator Operator

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

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

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

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

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

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

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

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

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

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

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

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

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

3. Levels of Non-Compliance for Generator Owner:

3.1.1 Level One: Not applicable.

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

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

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

E. Regional Differences

None identified.

F. Associated Documents

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

Version History

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

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.

Exhibit C

The complete development record of the formal interpretation

VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules

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Project 2008-11

Interpretation — VAR-002 — Voltage and Reactive — Generator Operations for Maintaining Network Voltage Schedules

Registered Ballot Body | Drafting Team Rosters

Status

The Standards Committee has posted a request for interpretation from ICF Consulting for VAR-002-1a. The recirculation ballot for this interpretation will end on January 15, 2009. The response to comments received from the initial ballot has also been posted.

The request asks:

1. Which requirements in VAR-002 apply to Generator Operators that operate generators that do not have automatic voltage regulation (AVR) capability?
2. Does the standard require a Generator Owner to acquire AVR devices to comply with the requirements in this standard?

In Purpose/Industry Need

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Proposed Standard	Supporting Documents	Comment Period	Comments Received	Response to Comments
Announcement **(7)** Interpretation **(8)** VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules Posted for 10-day Recirculation Ballot Window	ICF Consulting Request for Interpretation **(9)** VAR-002-1a	01/06/09 - 01/15/09 (closed) 10-day Recirculation Ballot Window		Announcement **(10)** Ballot Results **(11)**

Interpretation **(3)** VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules Posted for 10-day Ballot Window	ICF Consulting Request for Interpretation **(4)** VAR-002-1a	09/09/08 – 09/17/08 (closed) Ballot Window		Initial Ballot Results **(5)** Response to Comments **(6)**
Interpretation **(1)** VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules Posted for 30-day Pre-ballot Review	ICF Consulting Request for Interpretation **(2)** VAR-002-1a	08/07/08 – 09/08/08 (closed) Join Ballot Pool		

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Interpretation of VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules (Project 2008-11)

Request for Interpretation Received from ICF Consulting on June 16, 2008:

ICF Consulting's June 16, 2008 request for a formal interpretation of VAR-002-1a states:

"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."

VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

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

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R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

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

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

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

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

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

The following interpretation of VAR-002-1a was developed by a subset of the members of the Phase III and IV and Generator Verification standard drafting teams on July 29, 2008:

Please note that the interpretation response cites version 1a of VAR-002 as the ICF request did not specify a version.

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.

Background and Discussion

VAR-002-1a is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. Considered in the context that an out of service automatic voltage regulator and the lack thereof are functionally equivalent conditions will aid in the understanding of the intent of the requirements in VAR-002-1a.

The following explains how to interpret the requirements:

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. (underline emphasis added)

The intent of Requirement R1 is for the Generator Operator to inform its Transmission Operator that automatic voltage control capability is not available, which may be due to the automatic voltage regulator not functioning or the absence of one. Generator Operators operating generators not equipped with an automatic voltage regulator simply must inform the Transmission Operator that the generator is not capable of automatic voltage control.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings1) as directed by the Transmission Operator.

R2.1. *When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.*

R2.2. *When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.*

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

Requirement R2 allows a Transmission Operator to exempt generators from maintaining a generator voltage or Reactive Power output schedule.

Requirement R2.1 states that the Generator Operator must control voltage and reactive output in accordance with the schedule provided by the Transmission Operator using alternative methods when the automatic voltage regulator is not available. The action required is to control voltage or Reactive Power and the desired result is for the voltage schedule to be met. This requirement

applies to a generator irrespective of whether it is equipped with an out of service automatic voltage regulator or no automatic voltage regulator at all.

Requirement R2.2 is independent of the presence of an automatic voltage regulator and does allow the Generator Operator without an automatic voltage regulator to provide an explanation for not being able to comply with the Transmission Operator directed voltage schedule.

Similarly, Requirement R2 is also independent of the presence of an automatic voltage regulator but does allow the Transmission Operator to consider information provided by the Generator Operator in accordance with R1 and possibly R2.2 regarding the fact that the generator is not automatic voltage regulator equipped.

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

Whether or not a generator is equipped with an automatic voltage regulator is not relevant to either Requirement R4 or Requirement R5 Generator Operators of all generators without an automatic voltage regulator must comply.

June 16, 2008

Request for Interpretation:

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.

For more information, please contact:

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Telephone 713-445-2019
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Interpretation of VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules (Project 2008-11)

Request for Interpretation Received from ICF Consulting on June 16, 2008:

ICF Consulting's June 16, 2008 request for a formal interpretation of VAR-002-1a states:

"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."

VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

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

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R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

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

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

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

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

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

The following interpretation of VAR-002-1a was developed by a subset of the members of the Phase III and IV and Generator Verification standard drafting teams on July 29, 2008:

Please note that the interpretation response cites version 1a of VAR-002 as the ICF request did not specify a version.

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.

Background and Discussion

VAR-002-1a is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. Considered in the context that an out of service automatic voltage regulator and the lack thereof are functionally equivalent conditions will aid in the understanding of the intent of the requirements in VAR-002-1a.

The following explains how to interpret the requirements:

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. (underline emphasis added)

The intent of Requirement R1 is for the Generator Operator to inform its Transmission Operator that automatic voltage control capability is not available, which may be due to the automatic voltage regulator not functioning or the absence of one. Generator Operators operating generators not equipped with an automatic voltage regulator simply must inform the Transmission Operator that the generator is not capable of automatic voltage control.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings1) as directed by the Transmission Operator.

R2.1. *When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.*

R2.2. *When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.*

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

Requirement R2 allows a Transmission Operator to exempt generators from maintaining a generator voltage or Reactive Power output schedule.

Requirement R2.1 states that the Generator Operator must control voltage and reactive output in accordance with the schedule provided by the Transmission Operator using alternative methods when the automatic voltage regulator is not available. The action required is to control voltage or Reactive Power and the desired result is for the voltage schedule to be met. This requirement

applies to a generator irrespective of whether it is equipped with an out of service automatic voltage regulator or no automatic voltage regulator at all.

Requirement R2.2 is independent of the presence of an automatic voltage regulator and does allow the Generator Operator without an automatic voltage regulator to provide an explanation for not being able to comply with the Transmission Operator directed voltage schedule.

Similarly, Requirement R2 is also independent of the presence of an automatic voltage regulator but does allow the Transmission Operator to consider information provided by the Generator Operator in accordance with R1 and possibly R2.2 regarding the fact that the generator is not automatic voltage regulator equipped.

R3. *Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:*

R3.1. *A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.*

R3.2. *A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.*

In the case of generators not equipped with an automatic voltage regulator, Requirement R3 and associated sub-requirements simply require the Generator Operator to inform the Transmission Operator if and when such capability is installed.

R4. *The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.*

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

R4.1.1. *Tap settings.*
R4.1.2. *Available fixed tap ranges.*
R4.1.3. *Impedance data.*
R4.1.4. *The +/- voltage range with step-change in % for load-tap changing transformers.*

R5. *After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.*

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

Whether or not a generator is equipped with an automatic voltage regulator is not relevant to either Requirement R4 or Requirement R5 Generator Operators of all generators without an automatic voltage regulator must comply.

June 16, 2008

Request for Interpretation:

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.

For more information, please contact:

Jim Stanton
Telephone 713-445-2019
E-mail jstanton@icfi.com

Ballot Results	
Ballot Name:	Request for Interpretation - VAR-002-1 - ICF Consulting_in
Ballot Period:	9/9/2008 - 9/17/2008
Ballot Type:	Initial
Total # Votes:	181
Total Ballot Pool:	211
Quorum:	**85.78 % The Quorum has been reached**
Weighted Segment Vote:	90.37 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	59	1	40	0.889	5	0.111	5	9
2 - Segment 2.	8	0.8	7	0.7	1	0.1	0	0
3 - Segment 3.	47	1	35	0.946	2	0.054	3	7
4 - Segment 4.	12	1	11	1	0	0	1	0
5 - Segment 5.	43	1	31	0.886	4	0.114	1	7
6 - Segment 6.	25	1	19	0.905	2	0.095	1	3
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	3	0.3	3	0.3	0	0	0	0
9 - Segment 9.	5	0.3	2	0.2	1	0.1	1	1
10 - Segment 10.	9	0.6	5	0.5	1	0.1	0	3
Totals	**211**	**7**	**153**	**6.326**	**16**	**0.674**	**12**	**30**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services Company	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Consolidated Edison Co. of New York	Edwin Thompson		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	

1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Julien Gagnon	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang		
1	National Grid	Michael J Ranalli	Negative	View
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Negative	
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	lorees Tadros		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Abstain	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	American Electric Power	Raj Rana		
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Abstain	
3	City of Tallahassee	Rusty S. Foster		
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View

3	JEA	Garry Baker		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	James Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway		
5	Allegheny Energy Supply Company, LLC	Robert Loy	Negative	View
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Constellation Generation Group	Michael F. Gildea	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dynegy	Greg Mason		
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik		
5	Reedy Creek Energy Services	Bernie Budnik		
5	Reliant Energy Services	Thomas J. Bradish	Negative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	

5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	David Schiada	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	Frank D Cuzzort	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Abstain	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah		
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Reliant Energy Services	Trent Carlson		
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Jose Benjamin Quintas	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	ICF Consulting	Jim Stanton	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Utility Services LLC	Brian Evans-Mongeon	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	North Carolina Utilities Commission	Kimberly J. Jones	Abstain	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	View
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt		
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge		
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Consideration of Comments on Initial Ballot of Interpretation of VAR-002 for ICF Consulting

Summary Consideration: Several balloters indicated that the interpretation may be read as "requiring" that automatic voltage regulation is required, even if not installed at a facility. The interpretation states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation …. The standard has no stated requirement that each generator shall be equipped with an AVR.

Several balloters asked for clarification on how to acquire an "exemption" from the Transmission Operator. The Interpretation cannot include any additional requirements such as how exemptions are determined or implemented. However, Reliability Standard VAR-001-1a Requirement R3 requires the Transmission Operator to identify criteria for exempting generators from compliance with the requirement (identified in VAR-001-1a R4) to comply with the voltage schedule (provided by the Transmission Operator) in automatic voltage control mode and the requirement (identified in VAR-001-1a R6) to maintain or change voltage or reactive power schedules (provided by the Transmission Operator).

Some balloters indicated that this interpretation does not support the "original" intent of the predecessor Planning Standard and stated that the original intent of the predecessor standard was to require all generators to have AVR and operate in the automatic mode. The original Planning Standard used as a basis for Version 0 was III.C.S1 which stated "All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator." Neither the current standard nor the Interpretation state or reference this "intention".

Some balloters indicated that interpretations should be posted for comment before being balloted. The drafting team is aware that the NERC Standards Committee is considering proposing a revision to the Reliability Standards Development Procedure to include a comment period for interpretations.

The drafting team did not make any modifications to the interpretation based on the comments received.

Entity	Segment	Vote	Comment
FirstEnergy Energy Delivery First Energy Solutions Ohio Edison Company	1 3, 5, 6	Affirmative	FirstEnergy AFFIRMS the interpretation response provided in VAR-002a in response to questions raised by ICF Consulting. FirstEnergy agrees that all requirements of VAR-002 are applicable to all Generator Owner and Generator Operators as described in the interpretation response, regardless of whether or not the unit is equipped with an automatic voltage regulator (AVR). The interpretation response states "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

Entity	Segment	Vote	Comment
	4		generator equipped with an automatic voltage regulator that is out of service due to maintenance or failure." However, in FERC Order 693, one could conclude that the Commission assumes that the standard is predicated on the assumption that all bulk power system connected generator units are equipped with AVR. In paragraph 1881 the Commission states "Reliability Standard VAR-002-1 requires generator operators to operate in automatic voltage control mode, to maintain generator voltage or reactive power output as directed by the transmission operator, and to notify the transmission operator of a change in status or capability of any generator reactive power resource." The standard, as written, does not explicitly require AVR equipment on all synchronous generation units connected to the bulk power system. Currently, the need for AVR installations is described in a Transmission Owner's facility connection requirements (FAC-001) and/or Interconnection Agreements between and Transmission Owner and Generation Owner. FirstEnergy believes the interpretation is correct and accurate based on the present state of the VAR-002a standard. However, NERC should adjust the scope of the existing standard development project "Project 2008-01: Voltage and Reactive Control" to consider questions raised by this interpretation request. Through project 2008-01, the industry should reflect on the reliability need to mandate AVR installations on the appropriate subset of BES generation units within a TOP or BA footprint. The subset could be based on some % of total units or % of total MVA capability.
Response: Thank you for your support and comments for the future development of the standard. Your comments will be forwarded to the drafting team working on the further development of this standard for its consideration. Note that when a standard has an approved interpretation, the Reliability Standards Development Procedure includes the following language, which supports your recommendation, "The interpretation will stand until such time as the standard is revised through the normal process, at which time the standard will be modified to incorporate the clarifications provided by the interpretation."			
Hydro One Networks, Inc.	1, 3	Negative	Hydro One Networks Inc. casts a Negative vote with the following comments: 1. The interpretation as written could mean that AVR is required even if not installed at a facility. This is not the intent of the Standard. 2. The interpretation mentions that the TOP may provide exemptions but does not give a process to apply and grant such exemptions.

Entity	Segment	Vote	Comment
Response: 1. The interpretation states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation .... The standard has no stated requirement that each generator shall be equipped with an AVR. 2. The Interpretation cannot include any additional requirements such as how exemptions are determined or implemented. However, Reliability Standard VAR-001-1a Requirement R3 requires the Transmission Operator to identify criteria for exempting generators from compliance with the requirement (identified in VAR-001-1a R4) to comply with the voltage schedule (provided by the Transmission Operator) in automatic voltage control mode and the requirement (identified in VAR-001-1a R6) to maintain or change voltage or reactive power schedules (provided by the Transmission Operator).			
Hydro-Quebec TransEnergie	1	Negative	The interpretation is not clear, and may modify the intention of the standard in the sense that the requirement R3 could be interpreted to mean that an Automatic Voltage Regulator "AVR" is required if not already installed, when that is not the intention.
Response: The interpretation states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation .... The standard has no stated requirement that each generator shall be equipped with an AVR.			
National Grid	1	Negative	National Grid agrees with the comments made by NPCC and its other regional entities that requirement R3 could be interpreted to mean that an Automatic Voltage Regulator "AVR" is required if not already installed, when that is not the intention. The interpretation is not clear, and may modify the intention of the standard. The existing Standard requirement R3 clearly states: R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability. R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability. In addition there are compliance concerns on what would constitute sufficient notification by a GO to a TO that there was no AVR and if simply a Not Applicable would be an acceptable compliance reporting statement.

Entity	Segment	Vote	Comment
			Also, exemptions by the TO are mentioned in the interpretation. What are the processes for granting an exemption? What if one is not given to a unit that does not have AVR? National Grid believes more work is needed on the Interpretation and that NERC should consider adding comment periods to Formal Interpretations rather than just posting them for a preballot review and ballot. National Grid therefore must vote against this interpretation.
Response: 1. The interpretation states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation .... The standard has no stated requirement that each generator shall be equipped with an AVR. As the commenter points out, R3.1 and R3.2 require a status change notification – if equipment is not installed, there can be no change in status. The drafting team cannot speak for the Compliance Enforcement Authority. The Interpretation cannot include any additional requirements such as how exemptions are determined or implemented. However, Reliability Standard VAR-001-1a Requirement R3 requires the Transmission Operator to identify criteria for exempting generators from compliance with the requirement (identified in VAR-001-1a R4) to comply with the voltage schedule (provided by the Transmission Operator) in automatic voltage control mode and the requirement (identified in VAR-001-1a R6) to maintain or change voltage or reactive power schedules (provided by the Transmission Operator). The NERC Standards Committee is considering proposing a revision to the Reliability Standards Development Procedure to include a comment period for interpretations.			
Northeast Utilities	1	Negative	Northeast Utilities believes that VAR-002 R3 and the Interpretation could still be interpreted to mean that an Automatic Voltage Regulator (AVR) is required if not already installed, when that is not the intention. The interpretation is not clear, and may modify the intention of the standard. In addition, there are outstanding compliance concerns on what would constitute sufficient notification by a GOP to a TOP that there was no AVR, and if simply a “Not Applicable” would be an acceptable compliance reporting statement. Also, R2 and the interpretation require an exemption be granted by the TOP to the GOP - what are the processes and time frames for granting such an exemption? What if one is not given to a unit that has no AVR? NU believes more work is needed on the Interpretation and that NERC should consider adding comment periods to Formal Interpretations, rather than just posting them for a preballot review and ballot.
Response: 1. The interpretation response states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation .... The standard has no stated requirement that each generator shall be equipped with an AVR. AS the commenter points out, R3.1 and R3.2 requires a status change notification – if equipment is not installed, there can			

Entity	Segment	Vote	Comment
be no change in status. The Interpretation cannot include any additional requirements such as how exemptions are determined or implemented. However, Reliability Standard VAR-001-1a Requirement R3 requires the Transmission Operator to identify criteria for exempting generators from compliance with the requirement (identified in VAR-001-1a R4) to comply with the voltage schedule (provided by the Transmission Operator) in automatic voltage control mode and the requirement (identified in VAR-001-1a R6) to maintain or change voltage or reactive power schedules (provided by the Transmission Operator). The NERC Standards Committee is considering proposing a revision to the Reliability Standards Development Procedure to include a comment period for interpretations.			
California ISO	2	Affirmative	The interpretation provides a clear description of the responsibility of the generator operator without AVR on what they need to do to comply with the standard.
Response: Thank you for your comment and support.			
Independent Electricity System Operator	2	Affirmative	The IESO is concerned that the interpretation as written may send a wrong signal that generators are not required to be equipped with automatic voltage regulators. We therefore propose the leading sentence in the second paragraph be revised to: "The main objective of this standard is to mitigate reliability risks by requiring Generator Operators to notify Transmission Operators when removing automatic voltage regulators from service", although there are no requirements in the existing 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."
Response: The interpretation response states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation …. The standard has no stated requirement that each generator shall be equipped with an AVR. The Interpretation cannot include any additional requirements such as stating that the installation of AVR is required. Your comments will be forwarded to the drafting team working on the further development of this standard for its consideration.			
ISO New England, Inc.	2	Negative	This Interpretation will result in weakened Reliability: the original predecessor (Planning Standards = Version 0) of this Standard was intended to require AVRs on all generators and that they be operated in Auto mode. Additionally, a finding of the Blackout was a lack of this coordinated setting on Generators in the ECAR Region. ISO New England further believes that NERC should consider adding comment periods to

Entity	Segment	Vote	Comment
			Formal Interpretations rather than just posting them for a preballot review and ballot.
Response: The original Planning Standard used as a basis for Version 0 was III.C.S1 which stated "All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator." Neither the current standard nor the Interpretation state or reference this "intention". The NERC Standard Committee is currently working on the procedures for handling Interpretations. Your comments will be forwarded to it for consideration.			
Midwest ISO, Inc.	2	Affirmative	We agree that the standard should not oblige a generator to install equipment. However, it is important that this interpretation does not overrule interconnection requirements of the local transmission owner/operator. There may be some misunderstanding as well. While we heard people talk about generators that didn't have an AVR, they may be mistaken. Even then the alternators in cars have AVRs. What people might be thinking in some situations is that they have a generator that doesn't strictly maintain a constant voltage. Generator AVRs generally have a reactive droop feature that lets voltage drop as the MVA loading increases. The operator has to give the generator a new setpoint to return to a given voltage as the machine is loaded. It's quite possible that many people who think they don't have an AVR, actually do.
Response: Thank you for your comments and additional explanation.			
Consolidated Edison Co. of New York	3	Negative	Requirement R3 could be interpreted to mean that an Automatic Voltage Regulator is required when not already installed, and that is not the intention. The interpretation is not clear and may modify the intention of the standard. Exemptions by the TO are mentioned in the interpretation. It is not clear what the processes are for granting an exemption.
Response: The interpretation response states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation …. The standard has no stated requirement that each generator shall be equipped with an AVR. AS the commenter points out, R3.1 and R3.2 requires a status change notification – if equipment is not installed, there can be no change in status.			

Entity	Segment	Vote	Comment
The Interpretation cannot include any additional requirements such as how exemptions are determined or implemented. However, Reliability Standard VAR-001-1a Requirement R3 requires the Transmission Operator to identify criteria for exempting generators from compliance with the requirement (identified in VAR-001-1a R4) to comply with the voltage schedule (provided by the Transmission Operator) in automatic voltage control mode and the requirement (identified in VAR-001-1a R6) to maintain or change voltage or reactive power schedules (provided by the Transmission Operator).			
Allegheny Energy Supply Company, LLC	5	Negative	Generators that do not have an AVR, and are not exempted by the TOP would be reqired to install an AVR. Synchronous generators that do not have AVR's most likely are small or older units. This interpretation would allow the TOP to move the burden of voltage control to an entity that may not be best suited to provide the service.
Response: The interpretation response states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation …. The standard has no stated requirement that each generator shall be equipped with an AVR. The exemption is a formal acknowledgement of the Transmission Operator's decision on how to meet system needs utilizing resources, if installed and operational, considering their size, effect and condition. A statement by the Transmission Operator to require a piece of non-existent equipment to perform in a specified manner is meaningless.			
Reliant Energy Services	5	Negative	Reliant voted no for the following reason; Units without an AVR would be older, smaller and inefficient units. These units would not have a material impact on the BES. Even though the standard does not require an AVR the owner would probably opt to install an AVR rather than risk a violation. This unit should automatically be exempt without the TOP's approval. The "not receive a voltage schedule" is a concern. The standard should require the TOP to supply the GOP with a voltage schedule. Instead it gives the TOP the option to provide a voltage schedule or a reactive power schedule. The AVR must be in the auto voltage mode so shouldn't the TOP be required to supply a voltage schedule? Does operating the AVR in the auto voltage mode while requiring the generator to control to a reactive power schedule subject the BES to the risk of a voltage collapse event?
Response: The standard has no stated requirement that each generator shall be equipped with an AVR. The exemption is a formal acknowledgement of the Transmission Operator's decision on how to meet system needs utilizing resources, if installed and operational, considering their size, effect and condition. A statement by the Transmission Operator to require a piece of non-existent equipment to perform in a specified manner is meaningless.			

Entity	Segment	Vote	Comment
The commenter's concern about "not receive a voltage schedule" is related to the requestor's statements and not part of the Interpretation. VAR-001 contains requirements related to this concern. The Transmission Operator is in the best position to decide what is the most appropriate manner in which to maintain reliable operation in each area of the BES utilizing all the resources available.			
U.S. Army Corps of Engineers Northwestern Division	5	Affirmative	I do think there needs to be a requirement for the TOp to issue a waiver on following voltage or reactive schedules for those genearators that don't have an AVR. As it stands, there is no obligation for a waiver to be issued and this puts the GOp in the untenable position of using alternative means to follow voltage or reactive schedules.
Response: Thank you for your comment and support. The standard has no stated requirement that each generator shall be equipped with an AVR. The exemption is a formal acknowledgement of the Transmission Operator's decision on how to meet system needs utilizing resources, if installed and operational, considering their size, effect and condition. A statement by the Transmission Operator to require a piece of non-existent equipment to perform in a specified manner is meaningless. Whether automatic equipment control is available or not, the Transmission Operator is required by VAR-001 to issue a schedule or provide an exemption. R2.2 does provide recourse for the generator that cannot comply with the schedule.			
U.S. Bureau of Reclamation	5	Negative	Reclamation's concerns: The response to the request for interpretation for R1 offered that "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. . . . VAR-002-1a is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation." In R2 the interpretation provides "Requirement R2 allows a Transmission Operator to exempt generators from maintaining a generator voltage or Reactive Power output schedule." The standard should automatically exempt the Generator Operator from having to request an exemption or the exemption from the Transmission Operator is automatic when the generator does not have the physical equipment (automatic voltage regulator) (AVR). This would avoid the problem realibility problem when the Transmission Operator chooses to not provide the exemption when there is no physical equipment. The Generator Operator would have to attempt to follow voltage schedules with some non-automatic means. The interpretation of R2 offered: Requirement R2.1 states that the Generator Operator

Entity	Segment	Vote	Comment
			must control voltage and reactive output in accordance with the schedule provided by the Transmission Operator using alternative methods when the automatic voltage regulator is not available. The action required is to control voltage or Reactive Power and the desired result is for the voltage schedule to be met. This requirement applies to a generator irrespective of whether it is equipped with an out of service automatic voltage regulator or no automatic voltage regulator at all. Requirement R2.2 is independent of the presence of an automatic voltage regulator and does allow the Generator Operator without an automatic voltage regulator to provide an explanation for not being able to comply with the Transmission Operator directed voltage schedule. Similarly, Requirement R2 is also independent of the presence of an automatic voltage regulator but does allow the Transmission Operator to consider information provided by the Generator Operator in accordance with R1 and possibly R2.2 regarding the fact that the generator is not automatic voltage regulator equipped. This interpretation presumes that a Transmission Operator would exempt a generator if no AVR is present. Since the standard uses the word "may" it implies that a Generator Operator would be reguired to follow a voltage schedule even if there is no AVR installed, if the Transmission Operator chooses to not allow an exemption. Synchronous generators that do not have AVR's most likely are small or old units. The Transmission Operator would be aware of the generating unit and would have allowances for other means of controlling voltage. The interpretation would allow the Transmission Operator to move the burden of voltage control to an entity that may not be best suited to provide the service. In those cases, the Generator Operator would be required to attempt to follow a voltage schedule with plant operators. System voltages change continuously; even a set voltage schedule would require continuous excitation system adjustment. This would not add to the system reliability. The interpretation for conditions where there is no physical AVR should allow for an exemption.
Response: The standard has no stated requirement that each generator shall be equipped with an AVR. The exemption is a formal acknowledgement of the Transmission Operator's decision on how to meet system needs utilizing resources, if installed and operational, considering their size, effect and condition. A statement by the Transmission Operator to require a piece of non-existent equipment to perform in a specified manner is meaningless. Whether automatic equipment control is available or not, the Transmission Operator is required by VAR-001 to issue a schedule or provide an exemption. R2.2 does provide recourse for the generator that cannot comply with the schedule.			

Entity	Segment	Vote	Comment
Commonwealth of Massachusetts Department of Public Utilities	9	Negative	Requirement R3 can be interpreted to mean that an Automatic Voltage Regulator "AVR" is required if not already installed, when that is not the intention. The interpretation is not clear, and may modify the intention of the standard. R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following: R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stablizer and the expected duration of the change in status or capability. R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability. What would constitute sufficent notification by a GO to a TO that there was no AVR? The original predecessor (Planning Standards = version 0) were intended to require AVRs on all generators and that they be operated in Auto mode. A finding of the Blackout was a lack of this coordinated setting on Generators in the ECAR Region.
Response: The interpretation response states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation …. The standard has no stated requirement that each generator shall be equipped with an AVR. The Interpretation does not address the extent or the process used to provide notification. These would be addressed by additional requirements which are not allowed in an Interpretation. The original Planning Standard used as a basis for Version 0 was III.C.S1 which stated “All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator.” Neither the current standard nor the Interpretation state or reference this “intention”.			
New York State Reliability Council	10	Negative	We have voted NO because the VAR-002-1 Requirement R3 interpretation can be misinterpreted to mean that an Automatic Voltage Regulator "AVR" is required -- if not already installed -- when that is not the intention.
Response: The interpretation response states "The standard is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation …. The standard has no stated requirement that each generator shall be equipped with an AVR. As the balloter points out, R3.1 and R3.2 require a status change notification – if equipment is not installed, there can be no change in status.			

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Standards Announcement

Two Recirculation Ballots

January 6–15, 2009

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Recirculation ballot windows for the following projects are now open until 8 p.m. EST on January 15, 2009:

Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

The Regional Entity Compliance Managers group submitted a Request for an Interpretation of EOP-001-0 — Emergency Operations Planning Requirement R1. Under Requirement R1, the Balancing Authority must have operating agreements with adjacent Balancing Authorities that contain provisions for emergency assistance, including emergency assistance from remote Balancing Authorities. The request asked for the following clarifications:

- Define the scope and time horizon associated with "emergency assistance."
- Does "adjacent Balancing Authority" mean one or all adjacent Balancing Authorities?
- What is a "remote Balancing Authority?"
- Does a Balancing Authority participating in a Reserve Sharing Group under BAL-002-0 need additional operating agreements to be compliant with EOP-001-0 Requirement R1?

This version of interpretation includes edits to the version posted for initial ballot. The request and interpretation are posted on the following page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Interpretation of VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules (Project 2008-11)

ICF Consulting submitted a formal Request for Interpretation, which asked for the following clarifications:

- Which requirements in VAR-002 apply to Generator Operators that operate generators that do not have automatic voltage regulation (AVR) capability?
- Does the standard require a Generator Owner to acquire AVR devices to comply with the requirements in this standard?

The interpretation provides the following clarifications:

- 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.
- 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.

The request and interpretation are posted on the following page:
http://www.nerc.com/filez/standards/Project2008-11_VAR-002_Interpretation.html

Recirculation Ballot Process

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

Standards Development Process

The Reliability Standards Development Procedure 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 Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

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Interpretation of VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules (Project 2008-11)

Request for Interpretation Received from ICF Consulting on June 16, 2008:

ICF Consulting's June 16, 2008 request for a formal interpretation of VAR-002-1a states:

"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."

VAR-002-1a Generator Operation for Maintaining Network Voltage Schedules

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings[1]) as directed by the Transmission Operator.

R2.1. When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.

R2.2. When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.

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

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R3. Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:

R3.1. A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.

R3.2. A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

R4. The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.

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

R4.1.1. Tap settings.

R4.1.2. Available fixed tap ranges.

R4.1.3. Impedance data.

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

R5. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.

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

The following interpretation of VAR-002-1a was developed by a subset of the members of the Phase III and IV and Generator Verification standard drafting teams on July 29, 2008:

Please note that the interpretation response cites version 1a of VAR-002 as the ICF request did not specify a version.

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.

Background and Discussion

VAR-002-1a is predicated on the assumption that the generator has the physical equipment (automatic voltage regulator) that is capable of automatic operation. Considered in the context that an out of service automatic voltage regulator and the lack thereof are functionally equivalent conditions will aid in the understanding of the intent of the requirements in VAR-002-1a.

The following explains how to interpret the requirements:

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator. (underline emphasis added)

The intent of Requirement R1 is for the Generator Operator to inform its Transmission Operator that automatic voltage control capability is not available, which may be due to the automatic voltage regulator not functioning or the absence of one. Generator Operators operating generators not equipped with an automatic voltage regulator simply must inform the Transmission Operator that the generator is not capable of automatic voltage control.

R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings1) as directed by the Transmission Operator.

R2.1. *When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.*

R2.2. *When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.*

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

Requirement R2 allows a Transmission Operator to exempt generators from maintaining a generator voltage or Reactive Power output schedule.

Requirement R2.1 states that the Generator Operator must control voltage and reactive output in accordance with the schedule provided by the Transmission Operator using alternative methods when the automatic voltage regulator is not available. The action required is to control voltage or Reactive Power and the desired result is for the voltage schedule to be met. This requirement

applies to a generator irrespective of whether it is equipped with an out of service automatic voltage regulator or no automatic voltage regulator at all.

Requirement R2.2 is independent of the presence of an automatic voltage regulator and does allow the Generator Operator without an automatic voltage regulator to provide an explanation for not being able to comply with the Transmission Operator directed voltage schedule.

Similarly, Requirement R2 is also independent of the presence of an automatic voltage regulator but does allow the Transmission Operator to consider information provided by the Generator Operator in accordance with R1 and possibly R2.2 regarding the fact that the generator is not automatic voltage regulator equipped.

R3. *Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:*

R3.1. *A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.*

R3.2. *A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.*

In the case of generators not equipped with an automatic voltage regulator, Requirement R3 and associated sub-requirements simply require the Generator Operator to inform the Transmission Operator if and when such capability is installed.

R4. *The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.*

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

R4.1.1. *Tap settings.*
R4.1.2. *Available fixed tap ranges.*
R4.1.3. *Impedance data.*
R4.1.4. *The +/- voltage range with step-change in % for load-tap changing transformers.*

R5. *After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.*

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

Whether or not a generator is equipped with an automatic voltage regulator is not relevant to either Requirement R4 or Requirement R5 Generator Operators of all generators without an automatic voltage regulator must comply.

June 16, 2008

Request for Interpretation:

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.

For more information, please contact:

Jim Stanton
Telephone 713-445-2019
E-mail jstanton@icfi.com

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Initial Ballots:

Revisions to Violation Severity Levels for TOP-004-2 — Transmission Operations (Project 2008-16)

Since at least one negative ballot was submitted with a comment, a recirculation ballot will be held. The recirculation ballot will be held after the drafting team responds to voter comments submitted during this ballot.

The initial ballot for revisions to Violation Severity Levels for TOP-004-2 — Transmission Operations ended January 14, 2008. The ballot results are shown below. The Ballot Results Web page provides a link to the detailed results.

Quorum: 91.20 %
Approval: 93.93 %

Project page: http://www.nerc.com/filez/standards/Project_2008-16_Trans_Ops_VSLs.html

Interpretation of CIP-006-1a Requirement R4 for the US Army Corps of Engineers (Project 2008-15)

Since at least one negative ballot was submitted with a comment, a recirculation ballot will be held. The recirculation ballot will be held after the drafting team responds to voter comments submitted during this ballot.

The initial ballot for an interpretation of CIP-006-1a — Cyber Security — Physical Security of Critical Cyber Assets Requirement R4 (requested by the US Army Corps of Engineers) ended January 14, 2008. The ballot results are shown below. The Ballot Results Web page provides a link to the detailed results.

Quorum: 91.15 %
Approval: 97.39 %

Project page: http://www.nerc.com/filez/standards/Project2008-15_Interpretation_CIP-006-1a_US_Army_COE.html

Recirculation Ballots:

Interpretation of VAR-002-1a for ICF Consulting (Project 2008-11)

The ballot has passed and will be submitted to the NERC Board of Trustees for approval.

The recirculation ballot for the interpretation of VAR-002-1a — Generator Operation for Maintaining Network Voltage Schedules (requested by ICF Consulting) ended January 15, 2009. The final ballot results are shown below. The Ballot Results Web page provides a link to the detailed results.

Quorum: 91.47 %
Approval: 91.21 %

Project page: http://www.nerc.com/filez/standards/Project2008-11_VAR-002_Interpretation.html

Interpretation of EOP-001-0 Requirement R1 for Regional Entity Compliance Managers (Project 2008-09)

This recirculation ballot was conducted in error, and the results are void. Due to language changes by the drafting team, the interpretation should have been sent to a new initial ballot. A pre-ballot window will be initiated and announced in the next few days. Since this will be a new initial ballot, a new ballot pool will be formed during the pre-ballot window.

Project page: http://www.nerc.com/filez/standards/EOP-001-0_Interpretation_RECM.html

Ballot Criteria

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses.

Standards Development Process

The Reliability Standards Development Procedure 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 Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results

Ballot Name:	Request for Interpretation - VAR-002-1 - ICF Consulting_rc
Ballot Period:	1/6/2009 - 1/15/2009
Ballot Type:	recirculation
Total # Votes:	193
Total Ballot Pool:	211
Quorum:	**91.47 % The Quorum has been reached**
Weighted Segment Vote:	91.21 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	59	1	43	0.915	4	0.085	6	6
2 - Segment 2.	8	0.8	7	0.7	1	0.1	0	0
3 - Segment 3.	47	1	39	0.951	2	0.049	2	4
4 - Segment 4.	12	1	11	1	0	0	1	0
5 - Segment 5.	43	1	33	0.892	4	0.108	2	4
6 - Segment 6.	25	1	20	0.909	2	0.091	1	2
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	3	0.3	3	0.3	0	0	0	0
9 - Segment 9.	5	0.3	2	0.2	1	0.1	1	1
10 - Segment 10.	9	0.8	7	0.7	1	0.1	0	1
Totals	**211**	**7.2**	**165**	**6.567**	**15**	**0.633**	**13**	**18**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Jason Shaver	Affirmative	
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Affirmative	
1	Basin Electric Power Cooperative	David Rudolph		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	

1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	Consolidated Edison Co. of New York	Edwin Thompson		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Julien Gagnon	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang		
1	National Grid	Michael J Ranalli	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Negative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Negative	
1	Northeast Utilities	David H. Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	lorees Tadros		
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Richard Salgo	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Abstain	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	
2	California ISO	David Hawkins	Affirmative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	

3	City of Tallahassee	Rusty S. Foster	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen		
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Negative	View
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	James Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Alabama Electric Coop. Inc.	Tim Hattaway		
5	Allegheny Energy Supply Company, LLC	Robert Loy	Negative	View
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	View
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Constellation Generation Group	Michael F. Gildea	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dynegy	Greg Mason	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	

5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern States Power Co.	Liam Noailles	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Thomas Piascik		
5	Reedy Creek Energy Services	Bernie Budnik		
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Affirmative	
5	Southern California Edison Co.	David Schiada	Affirmative	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	Frank D Cuzzort	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Entergy Services, Inc.	William Franklin	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Robert C. Williams	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Reliant Energy Services	Trent Carlson		
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto	Affirmative	
6	Tampa Electric Co.	Jose Benjamin Quintas	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8	ICF Consulting	Jim Stanton	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Utility Services LLC	Brian Evans-Mongeon	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	North Carolina Utilities Commission	Kimberly J. Jones	Abstain	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Affirmative	

10	New York State Reliability Council	Alan Adamson	Negative	View
10	Northeast Power Coordinating Council, Inc.	Edward Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge		
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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